HOUSTON ENERGY TRANSITION INITIATIVE

GREATER HOUSTON PARTNERSHIP

CHARGING UP THE ENERGY TRANSITION IN HOUSTON:

EXPLORING FUTURE ELECTRICITY DEMAND

MISSION POSSIBLE PARTNERSHIP

RMI

PREFACE

This report is the result of work by the Houston Energy Transition Initiative (HETI), a strategic initiative led by the Greater Houston Partnership, dedicated to strengthening Houston's leadership as the Energy Capital of the world. This work is generously supported by the Mission Possible Partnership (MPP), an alliance that supports public and private sector partners working on the industry transition towards net-zero greenhouse gas emissions by 2050, and RMI, an independent non-profit focused on transforming global energy systems through market-driven solutions to align with a 1.5 degree C future, with a grant provided by the Bezos Earth Fund.

The economic vitality and growth of the region's economy is inextricably tied to the energy industry, and the industry is changing rapidly to meet growing global energy demand while simultaneously lower emissions. HETI builds on the best of traditional energy skills and systems to leverage Houston's industry leadership to accelerate global solutions for an energy-abundant, low-carbon future. HETI's objective is to create a vision and a blueprint for growing the region's economy, exporting low-carbon products and expertise, equitably creating new jobs, and helping the city of Houston achieve the goals of its Climate Action Plan.

This perspective complements the broader efforts of HETI, including reports such as "Houston Leading the Energy Transition" (June 2021), "Houston as the epicenter of a global clean hydrogen hub" (June 2022), and "Perspective on the energy transition capital of the world – Houston's opportunity to win by catalyzing capital formation" (October 2022). HETI works on various areas of energy transition that are relevant to the Houston region, including efforts on decarbonization of industry, carbon capture, utilization, and storage (CCUS), clean hydrogen and capital investment.

The energy transition will reshape Houston's economy and the role Houston will play in the global economy. This report examines the opportunity to develop a roadmap to a sustainable, resilient, and low-carbon electricity grid for the greater Houston region through the following lenses:

1. **Electrification scenarios.** How will the energy transition impact electrification and technology adoption in the industrial, transportation, and buildings sectors?
2. **Growth in electricity demand.** What is the possible range of new electric loads from electrification of industrial processes and facilities, transportation, and buildings?
3. **Impacts of electricity demand on grid infrastructure.** What are the implications for grid infrastructure planning from potential increases to hourly and annual electricity demand?
4. **Changes to GHG emissions.** How will the various electricity growth scenarios change GHG emissions within the Houston region?

There is significant opportunity for growth in electrification within the Houston region with its established ecosystem of power management stakeholders, such as corporations, utilities, ERCOT, PUCT, policymakers, and communities. This report evaluates the impact on grid demand of potential Houston regional electrification scenarios associated with the energy transition and provides insights to support Houston's leaders as they plan and prepare for key energy transition and decarbonization efforts in the region more cost effectively with less risk.

The intended audience for this report includes members of the power management ecosystem, such as businesses, utilities, regulatory bodies, non-profit organizations, academic institutions, policymakers, consumers, and other stakeholders with an interest in Houston's future in energy transition. A synthesis of this effort, along with a call to action for the various stakeholders in the Houston power ecosystem, concludes this report.

This paper includes statistics, forecasts, and other figures obtained from publicly available sources, members of the Greater Houston Partnership, and interviews with subject matter experts. The main body of the report is a summary of the findings. A detailed set of analyses that underpins the report can be found in the appendix. Estimated projections of electrification associated with energy transition technology adoption are context specific and reflect a particular set of conditions (detailed in appendix). While much of the quantitative data included in the analysis looks forward to 2030 and 2050 with current state assumptions, the report also summarizes the potential impact that federal incentives such as the IRS guidance on 45V associated with the Inflation Reduction Act (IRA) of 2022 could create for energy transition-related business ventures, projects, and assets.

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PART 01

EXECUTIVE SUMMARY

Houston is poised to lead the transition to an energy-abundant and low-carbon future with its existing energy infrastructure, workforce, and history of innovation. This transition presents vast business opportunities for Houston that could involve equally large shifts in regional electricity needs. A reliable, resilient, and low-carbon electricity grid is a key enabler for the Houston region's ability to continue growing its economy and population.

Many decarbonization solutions will require electricity, and, as a result, demand for electricity in the Houston region will grow in the future. This report evaluates the impacts of increased electricity demand in the context of proposed regional decarbonization efforts to understand the implications of the energy transition on Houston's electricity grid.

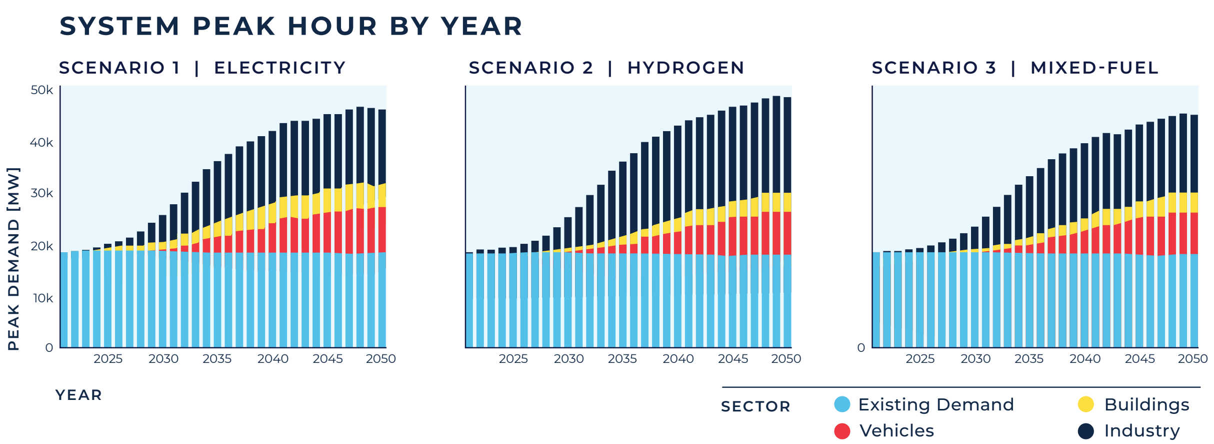
This work seeks to develop insights for the industrial, transportation, and buildings sectors, including large-scale hydrogen and carbon capture and storage projects in the Houston region. The report evaluates potential future electricity consumption and develop insights for possible impacts to grid infrastructure in Houston across scenarios representing moderately aggressive growth in low-carbon solutions with varying levels of electricity intensity. These scenarios are not meant to be a forecast, they represent hypothetical decarbonization futures for Houston but do not evaluate the economics of competing solutions and do not consider state-level policy and advocacy impacts to demonstrate a business case for any specific solution.

The Houston region's future electricity consumption, capacity demand, grid infrastructure needs, and hydrogen production, among many other factors, are highly uncertain over the analysis timeframe from now to 2050. This report acknowledges that there are many options to meet peak demand by 2050 and many possible scenarios to represent these hypothetical decarbonization futures for Houston, including distributed energy resources, in-market energy storage, dispatchable power, off-grid generation, and adoption of new transmission and distribution technology. This analysis presents a view of future electricity demand and grid infrastructure needs after 2030 within the CenterPoint service territory, which is a primary transmission and distribution utility covering most of the Houston Metropolitan Statistical Area[1,2], if electricity is to play a role in the decarbonization of Houston's industry and economy.

A 25% growth in electricity system peak demand by 2030 and 150% growth by 2050 across the analyzed area of Houston is estimated, even in the base scenario with higher deployment of less electricity-intensive solutions like carbon capture and storage (CCS) (Figure E.1).

Average annual consumption growth from now to 2030 is calculated to be 4-5%/year in Houston. This estimate is moderately higher than the range of annual growth over the past decade in the CenterPoint service territory, which has varied from 1-5% annually between 2013 and 2022. Industry, especially hydrogen production, will be an important driver for electricity growth in Houston through the energy transition. Figure E.2 shows electricity consumption for all the industrial end uses considered in this analysis: blue and green hydrogen production, point-source CCS, process heat, machine drive, and facility demand. System peak demand could be even higher in 2030 and 2050 depending on hydrogen production route and export demand, which is evaluated in sensitivity analyses (see Figure 8).

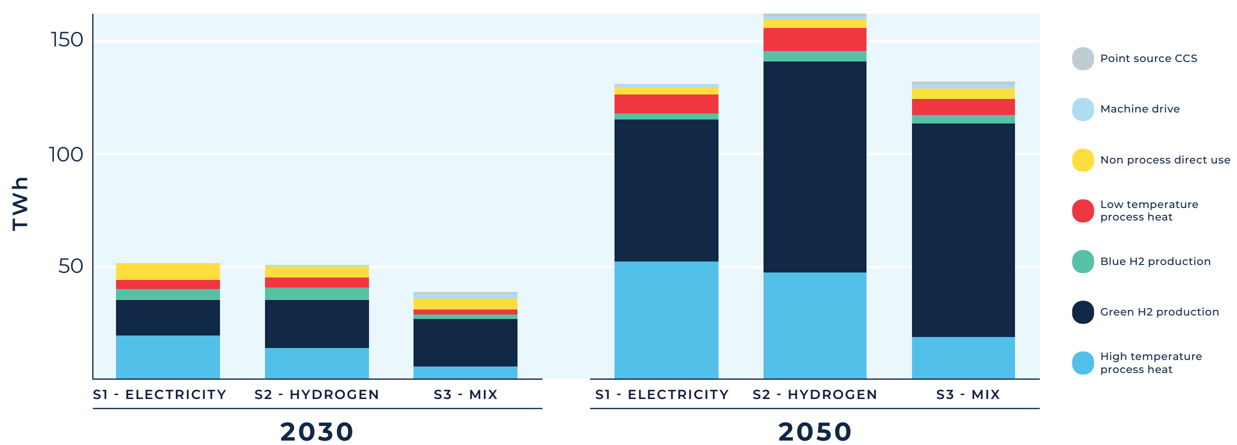
FIGURE E.1.
Decarbonizing Houston transportation, buildings, and industry could increase electricity system peak demand by at least 2.5x by 2050 in all scenarios



[1] These demand scenarios do not include the future development of servers to support AI or bitcoin investments beyond those already in place.

FIGURE E.2.
The majority of electricity consumption growth could come from industrial heat electrification and hydrogen production

INDUSTRY ELECTRICITY CONSUMPTION BY END USE



In the scenarios evaluated, CenterPoint distribution and transmission infrastructure buildout would need to grow slightly to moderately by 2030 to serve new industrial, transportation, and buildings demand[ii]. However, if businesses and consumers in Houston want to pursue a decarbonized, electricity-powered future, these scenarios imply the need for a substantial shift in the physical structure and operation of the grid, supported by demand flexibility and energy efficiency, as well as changes to planning processes by 2050.

In 2030, the level of peak demand growth would necessitate a few extra distribution feeders for electrification of transport and buildings and transmission lines for industrial electrification. By 2050, this report estimates that CenterPoint may need about 10% higher annual distribution feeder buildout for the analyzed transport and building electricity demand (Figure E.3). These results do not consider the impact of demand flexibility, storage, or distributed generation.

An additional total of 50-200 138 kV transmission lines (or 3-7 additional lines built annually) is estimated to be needed to serve future industrial electricity demand by 2050 (Figure E.4). These results do not consider the impact of demand flexibility or behind-the-meter generation. The report emphasizes that additional 138 kV lines alone is not an adequate path forward for the region. Technologies such as higher voltage alternating current (AC) lines, high voltage direct current (HVDC) lines, or grid enhancing technologies (GETs) would likely also be needed to help meet demand. Additionally, more hydrogen could be produced elsewhere and transported to the Houston region via pipeline.

[ii] Load growth from other sources such as data centers or cryptomining facilities which could significantly increase demand within the CenterPoint service territory is not considered.

Additional solutions such as demand flexibility, energy efficiency, and distributed generation may help alleviate grid stress, though they cannot fully eliminate grid infrastructure needs. Significant portions of electricity demand from transport, buildings, hydrogen electrolyzers, and industrial process heat could be flexible (discussed in greater detail in the Results section and Appendix). Clean peaking capacity and storage could help meet electricity needs during high demand. New transmission and distribution technologies could be adopted to make the current grid more efficient or expand grid capacity at lower cost. Additionally, energy efficiency measures across all sectors could help reduce peak capacity demand. Finally, generation located near load, from sources such as rooftop solar and large-scale behind-the-meter generation for industrial load, may help alleviate grid stress. Given the complexities of the grid, further analysis is needed to explore the impact of demand flexibility, energy efficiency, and distributed generation in greater detail.

All parties, including corporations, utilities, ERCOT, PUCT, and policymakers, should proactively prepare for the possibility of additional generation, transmission, and distribution infrastructure, as well as demand flexibility, energy efficiency, and distributed generation, given the potential for massive growth in electricity demand if Houston is to leverage electricity in the energy transition.

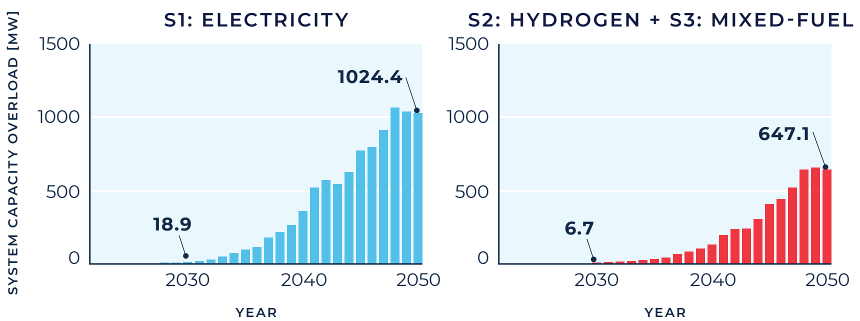
The scale of electrical grid infrastructure buildout implied by the scenarios is massive but not entirely unprecedented in Texas. However, waiting to invest in grid infrastructure could limit the region's business opportunities for the energy transition, especially when considering long lead times needed for transmission infrastructure. While market forces and public incentives certainly play a role in decarbonization, decisive action by Houston's businesses, policymakers, and consumers also determine the region's path forward.

Corporations could signal their interest in electricity-powered solutions individually and perhaps collectively to their utilities, considering the time scale of today's business cycles alongside the longer-term view more appropriate for grid infrastructure (on the order of 10 years). Utilities and ERCOT could take a deeper dive into load growth, especially from industry, and begin discussions on how best to equitably finance new grid infrastructure. Utilities, ERCOT, PUCT, and policymakers could also work on creating favorable market designs for customers to leverage the demand flexibility and dispatchability of new electrified technologies while aiding reliability and emissions reductions.

The research presented in this study was primarily focused on developing demand-side insights for electricity growth for Houston through the energy transition. Given the enormous potential growth in demand within the scenarios detailed in this report, further research by subject matter experts within the Houston region to explore complexities within the regional power system and supply-side insights into specific solutions is recommended.

FIGURE E.3.
Transportation and building electrification could require higher distribution feeder buildout per year

ANNUAL SYSTEM OVERLOAD [MW] BY SCENARIO



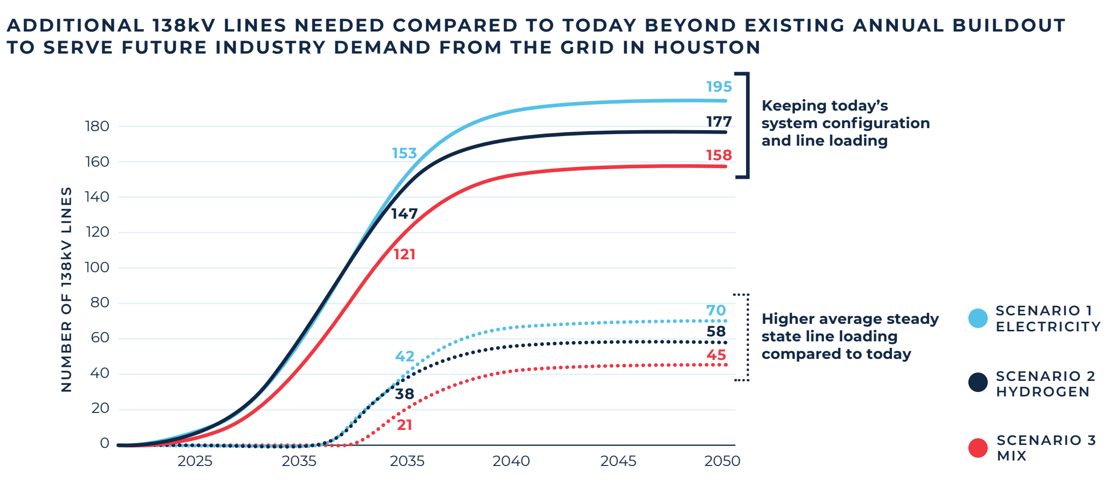
@100% LOADING

	SCENARIO 1	SCENARIO 2/3
2050 OVERLOAD	1024 MW	647 MW
EQUIVALENT 12 KV FEEDERS	~79 FEEDERS	~50 FEEDERS

Rated Feeder Capacity for 12 kV: ~ 13 MW

*Note: System capacity overload refers to the total overload across all feeders. Load growth is assumed to be spread evenly across distribution feeders (a simplifying assumption—in reality feeder loading will depend on customer needs in a given area). If the feeder is loaded greater than its rated capacity, then it is considered overloaded.

FIGURE E.4.
Industrial decarbonization will benefit from transmission system expansion



Constraints to Large Tx buildout:
Limited Rights-of-way and substation sites, 138kV fault duties, distance from generation to load

Solutions:
Multi-technology approach–higher-volatage AC Tx lines, HVDC, GETs

INTRODUCTION

Electricity and hydrogen have critical roles to play in Houston's cleaner future energy system.

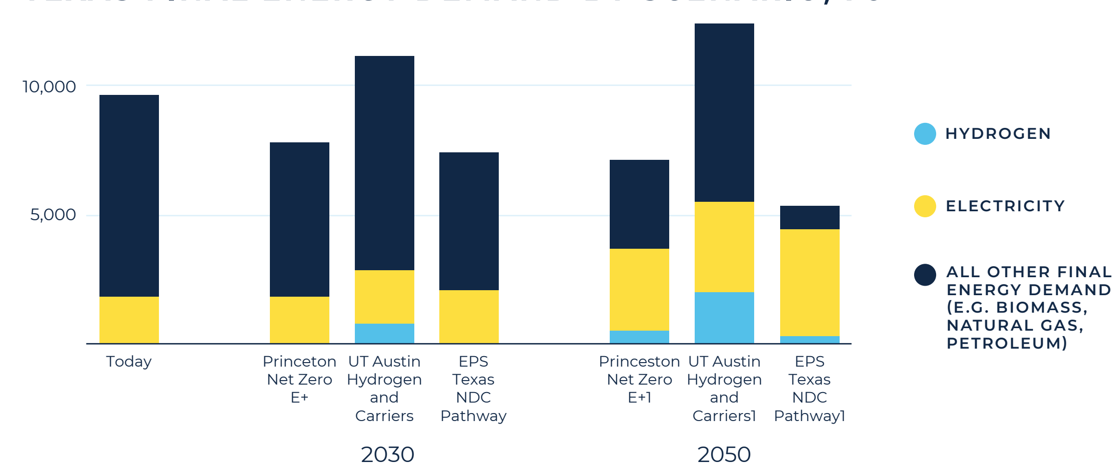
Houston has earned its title as the energy capital of the world. Texas produces more primary energy than any other US state, and ~60% of Houston Metro jobs have come from refining, petrochemicals, upstream, and midstream industries over the last 30 years.[3,4,5] With its deep energy expertise and innovation culture, Houston has the foundation to continue leading through the clean energy transition.

For Houston, the energy transition presents both an incredible business opportunity and significant risks that accompany rapid energy shifts. Global, national, and state deep decarbonization analyses suggest that tomorrow's global energy system will look much different from today. In the International Energy Agency (IEA) and McKinsey global scenarios for deep decarbonization[7,8] which reduce emissions by half or more by mid-century compared to today, clean electricity and hydrogen (which can be produced with electricity) grow from providing 20% of final energy today to over 25% in 2030 and over 50% in 2050.

Clean electricity and hydrogen will play key roles in the Texas energy transition. Figure 1 shows the Texas energy demand results from decarbonization scenarios created by Princeton[9], UT Austin[10], and Energy Innovation[11]. Electricity demand grows 10-50% per decade in these scenarios. While there is significant uncertainty, each of these analyses predict that electricity and hydrogen (which can be produced with electricity) will play growing roles.

FIGURE 1.
Texas final energy demand by scenario

TEXAS FINAL ENERGY DEMAND BY SCENARIO, PJ



Crucially, recent events suggest a clean hydrogen economy is coming to Houston. In May 2023, the Hydrogen Council reported that ~10% of recently announced clean hydrogen projects in North America are located in Texas . In October 2023, DOE selected the Gulf Coast Hydrogen Hub (HyVelocity), centered in Houston, as one of seven hubs across the country in its Regional Clean Hydrogen Hubs program. Beyond the United States, Texas could export hydrogen globally, including to regions such as Europe and Asia where it is expensive to produce hydrogen locally. This would increase Texas production beyond that shown in Figure 1 as the Princeton, UT Austin, and Energy Innovation scenarios do not consider hydrogen for export.

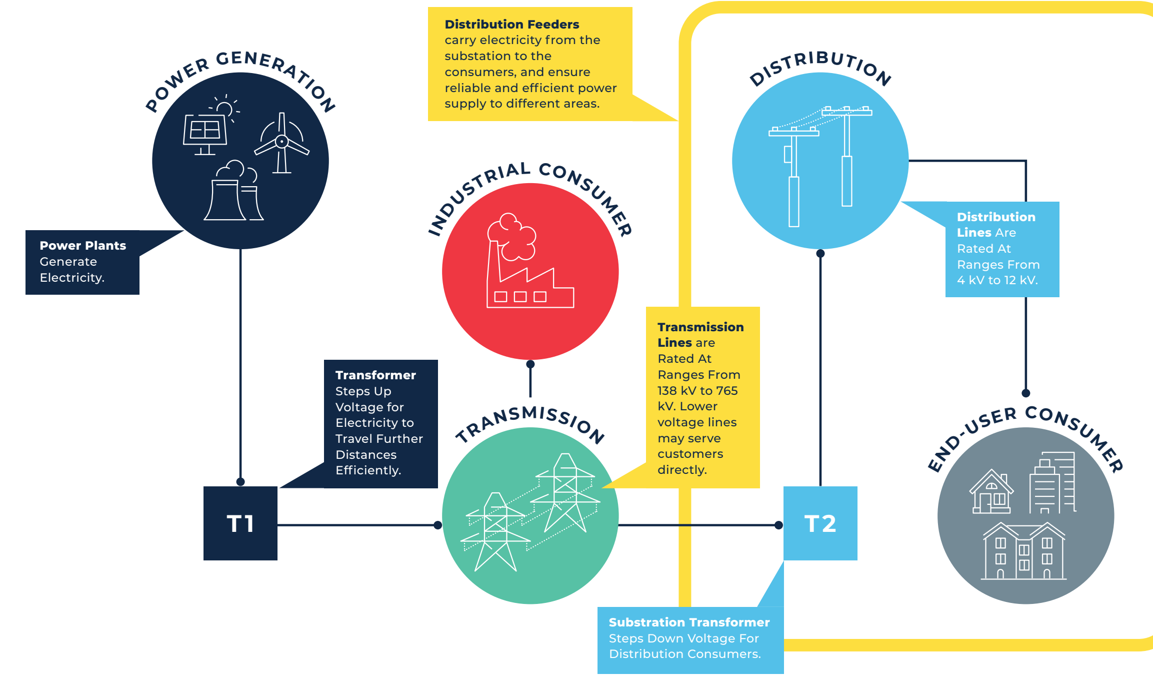
Clean electricity and hydrogen-powered solutions could also help Houston address current environmental challenges, including the disparate pollution burden borne by marginalized communities. Historically, Houston has grappled with severe air pollution. Many low-income communities, often predominantly consisting of people of color and immigrant populations, have been disproportionately affected by the detrimental health impacts of industrial activities, traffic emissions, and proximity to polluting facilities. The Texas Commission on Environmental Quality (TCEQ) has identified several areas in Houston as non-attainment zones for ozone and other pollutants that can contribute to respiratory issues, cardiovascular problems, and a range of health disparities among residents.[14] By transitioning to clean electricity-powered solutions across transportation[15], buildings[16], and industry[17], Houston can meaningfully reduce air pollutants and improve the health and well-being of all Houston residents, including its most vulnerable populations.

A key first step to ensure Houston can seize the opportunities of electricity-powered energy transition solutions is to understand the scale of potential change ahead for the electricity system. Few analyses have evaluated future electricity needs and corresponding grid infrastructure impacts at the level of a city. Grid infrastructure (see the call-out box below for more information) can have lead times on the order of 10 years, and therefore examining the future many years out is critical. Utilities[18] and ERCOT[9], which hold key responsibilities in the long process of building grid infrastructure, have started examining new electricity demand especially from electric vehicles. However, little work has been done to examine the impact of industrial loads in Houston. At such a localized geographic scale, it is important to understand in greater detail than existing global, national, and state-level scenarios which technologies may be connecting to the grid.

WHAT IS THE ELECTRIC GRID?

A traditional electric grid with bulk power generation

We focus on the grid elements highlighted in yellow in the analysis



Hydrogen, electricity-powered heat pumps, thermal energy storage, and electric boilers could support decarbonizing Houston's highest emitting heavy industries.

Hydrogen, industrial heat pumps, thermal energy storage (also known as thermal batteries), and electric boilers are technologies powered by electricity and have reached or are nearing commercialization. These technologies could help decarbonize Houston's highest emitting heavy industrial sector and ensure that the energy transition is energy efficient.

Low-emissions hydrogen will be eligible for rich US and EU incentives. Incentives will also make hydrogen produced in Houston attractive for export internationally.[20] As summarized in the call-out box below, there are two primary methods for producing low emissions hydrogen: blue and green hydrogen.[21] Blue hydrogen is produced via steam or autothermal reforming methane from natural gas, producing molecular hydrogen (H_2) and carbon dioxide (CO_2), which is then captured. Green hydrogen, also known as electrolyzer hydrogen, is produced using electricity to split water into hydrogen and oxygen. No additional CO_2 is emitted during this process, assuming electrolyzers are powered by completely clean electricity. Hydrogen produced without any carbon emissions control is known as gray hydrogen.

Clean hydrogen is eligible for tax credits under the Inflation Reduction Act (IRA) Section 45V. The IRA creates value tiers for the tax credit based on clean hydrogen emissions intensity. The lowest emissions intensity (<0.45 kg CO_2e lifecycle emissions per kg hydrogen) tier is valued highest at \$3/kg H_2.[22,23] The US Department of Treasury released guidance on the clean hydrogen tax credit in December 2023, including clarification on how hydrogen producers can qualify for the highest tier tax credits.[24] Treasury will be accepting comments on the guidance for the next couple months, and it will take corporations additional time to interpret and make use of tax credits. As a result, the implications for the tax credit on the economics of production routes for clean hydrogen will emerge with time.

Electrolyzer hydrogen, when paired with clean electricity, is likely to qualify for the highest tier of tax credits ($3/kg H_2) from the IRA Section 45V. Additionally, EU institutions like the European Hydrogen Bank[25] which support hydrogen import have strict definitions and greenhouse gas (GHG) emission[26] targets for electrolyzer hydrogen, which the EU defines as renewable hydrogen.[27] These guidelines further enhance the potential for exporting green hydrogen to Europe if the hydrogen is produced with clean electricity.

Blue hydrogen is also eligible for IRA Section 45V incentives[28, iii] currently at lower value tiers of tax credits but potentially eligible for higher value tiers if produced from natural gas at low carbon intensity. These valuations will depend on finalized guidance from the US Department of Treasury. Blue hydrogen producers may also extract value[29] from the 45Q Carbon Oxide Sequestration tax credit[30] in the IRA.

RMI analysis projects that green hydrogen could reach cost parity with blue hydrogen by 2030, as shown in Figure 2, especially in regions like Texas with relatively low electricity prices.[31] Additionally, RMI estimates that as electrolyzer capital costs decrease[32], year-round operation at full capacity may no longer be necessary to recoup high investment costs. These cost parity projections are dependent on electricity prices for green hydrogen, and electrolyzer technology could operate flexibly in the future in response to market or emissions signals and reduce curtailment of intermittent renewable resources like wind and solar.[33, 34, 35]

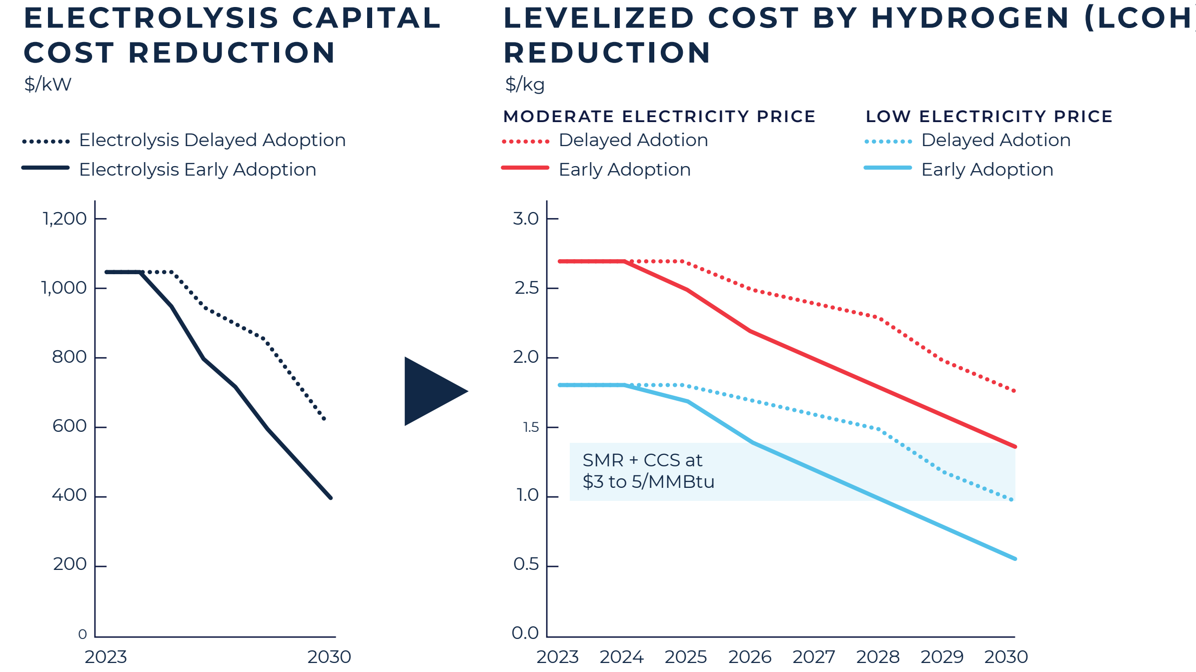
UNDERSTANDING THE HYDROGEN RAINBOW

Hydrogen is often described in the context of colors. The color indicates the process for producing the hydrogen, however, ultimately, all colors make the same final product that can be used interchangeably. In this report, blue and green hydrogen are primarily discussed and some additional information on each is noted below.

	BLUE HYDROGEN	GREEN HYDROGEN
Source of hydrogen	Natural gas (CH_4)	Water (H_2O)
How hydrogen is produced	Molecules of methane (CH_4, from natural gas) are split in the steam methane or autothermal reforming process. CCS systems capture CO_2 emitted as a byproduct.	Molecules of water are split using an electrolyzer powered by electricity
IRA tax credits	45V, 45Q	45V
Electricity intensity	Depends on process but around 3 kWh/kg	54 kWh/kg hydrogen
Emissions intensity considerations	Upstream methane leakage, CCS capture and storage efficiency	Emissions intensity of electricity powering the electrolyzer

[iii] RMI analysis[32] assumes a methane leakage rate of 0.6%, thus increasing the GHG emissions of blue hydrogen, rendering it ineligible for higher value tiers of 45V. This rate is comparable to those used in other analyses.

FIGURE 2.
Estimated hydrogen costs through time considering IRA incentives



Source and notes: RMI analysis[32]. Cost reduction potential with early adoption or delayed deployment of electrolysis. Assumptions: Uninstalled capex for a PEM stack + balance of plant starting at $1050/kW in 2023; Utilization rate assumed to be 50%; LCOH includes IRA 45Q for SMR + CCS and IRA 45V for electrolysis; Moderate electricity price: $40/MWh represents average renewable costs with IRA 45Y credits; Low electricity price: $25/MWh represents low renewables costs with IRA 45Y credits. Early and delayed adoption represent hypothetical scenarios in which cost reductions are realized earlier or later due to the acceleration of cost decline seen from accelerating investments.

Technologies that deliver heat using electricity offer new opportunities to decarbonize process heat at higher overall efficiency than hydrogen. The DOE recognized the importance of this topic and created the Industrial Heat Shot, one of the Department's Earthshot series.[36]

Industrial heat pumps[37] can deliver low-temperature process heat needs (less than 280°C[38] by using electricity to drive mechanical processes which add energy to upgrade waste heat. These industrial heat pumps use the same principles as residential ones, and indeed, many of the leading manufacturers[39] serve both markets. Industrial heat pumps notably offer energy savings as high as 32%[40] compared to conventional technologies like natural gas boilers. While this technology has not yet been widely adopted in the US, industrial heat pumps are well-established technologies in Europe and Asia. Organizations like the American Council for an Energy-Efficient Economy (ACEEE)[40], Energy Innovation[41], and Lawrence Berkeley National Lab[42] have published reports with recommendations to support deployment in the US, and the Industrial Heat Pump Alliance[43] brings together heat pump suppliers and large energy users.

Thermal energy storage is a promising electrified solution for medium to high-temperature process heat needs. The most commercialized form of this technology uses electricity to heat materials like bricks, sand, or rocks[44] to temperatures over 1600°C[45]. That heat can then be released when needed by an industrial user, or it can be used to generate electricity[46] using a steam turbine or other technologies. Notably, thermal energy storage technologies can decouple power supply from heat supply[47], charging when market signals indicate electricity is clean and cheap while maintaining a constant delivery of heat to the industrial facility. Proposed rules on the IRA Section 45X Advanced Manufacturing Production Credit indicate thermal batteries will be eligible for battery module incentives[48]. Electric boilers can provide heat up to 1800°C and may be able to serve similar roles as thermal energy storage.[49]

FIGURE 3.
Summary of policies incentivizing emerging industrial decarbonization technologies

INDUSTRIAL HEATING

INDUSTRIAL HEATSHOT AND IRA 45X

- Industrial heatshot
  - Part of DOE Earthshot program
  - Research, development, and demonstration
  - Funded from Bipartisan Infrastructure Law + Inflation Reduction Act
  - $156 million (2023) for industrial decarbonization
  - $70 million (2023-2028) for electrifying process heat
- IRA 45X: thermal batteries qualify as a battery module for the Advanced Manufacturing Production Credit

HYDROGEN

IRA 45V Clean Hydrogen Production Tax Credit

- $3/kg credit is more than 2x the market price of gray H_2 in the US
- Cannot be stacked with 45Q

Carbon Intensity (kg CO_2e/kg H2)	Max Hydrogen PTC Credit ($/kg H2)*
0-0.45	$3.00
0.45-1.5	$1.00
1.5-2.5	$0.75
2.5-4	$0.60

IRA 45Q Carbon Oxide Sequestration Credit

- New qualifying facility and capture technology must be placed in service by end of 2033
- Cannot be stacked with 45V

Type of Project	Max Credit ($/t CO_2)
Industrial Facility (Non-EOR/non-utilized)	$85
Industrial Facility (Used in EOR/ utilized)	$60

Evaluation of potential future electricity consumption and grid impacts in a decarbonized Houston.

This report begins filling the gap in knowledge on future electricity needs and corresponding grid infrastructure impacts in Houston. The potential impact of transportation, buildings, and industry decarbonization on electricity consumption and capacity demand in Houston is evaluated. The report takes a particularly close look at the industrial sector, examining electricity needs of technologies used in hydrogen production, heat production, and carbon capture. The focus area for the study is the CenterPoint service territory, a major transmission and distribution utility in the Houston region, and the report examines grid infrastructure needs as well as greenhouse gas reduction potential.

SCENARIOS

The report considers three scenarios that explore future electricity consumption, peak demand by hour, grid infrastructure impacts, and potential GHG emissions reductions in the service territory of CenterPoint, one of Houston's key transmission and distribution utilities.

The scenarios present different ways to achieve full implementation of decarbonization solutions in transportation, buildings, and industrial sectors by 2050. Full implementation of decarbonization solutions means that these scenario variables apply low or zero carbon solutions to each sector's technologies and end uses. This approach does not guarantee net zero emissions or compliance with a global temperature rise goal, as a full evaluation of carbon budgets and negative emissions technologies[iv] is outside the scope of this analysis. Each scenario assumes the energy transition proceeds along an s-curve (slow growth initially followed by exponential change) and uses scenarios such as the IEA World Energy Outlook Net Zero pathway to build a view of 2030. Within these scenarios, no comprehensive bottom-up analysis of planned and announced projects is developed to craft a 2030 outlook. These scenarios also do not incorporate economics of decarbonization solutions. See the appendix for a full list of scenario variables.

The three base scenarios analyzed are summarized below, informed by existing data and reports[v] as well as discussions with HETI members[50] participating in the Power Management working group.

SCENARIO 1

Electricity-powered Houston:

Assumes direct electrification of road transportation, building heating, low temperature process heat, and some high temperature process heat. Hydrogen also decarbonizes high temperature process heat.

SCENARIO 2

Hydrogen-powered Houston:

Assumes hydrogen powers some medium and heavy duty transport as well as some high-temperature process heat. Building heat, what remains of transport and high-temperature process heat, and low temperature process heat electrifies. Some point-source CCS decarbonizes high-temperature process heat.

SCENARIO 3

Mixed-fuel:

Similar to Scenario 2, but also assumes some low temperature and more high temperature process heat decarbonizes with point-source CCS.

FIGURE 4.
Summary of scenarios in 2050

2050 HOUSTON SCENARIOS SUMMARY				
(Transportation)	(Buildings)	(Industry)		H_2 Produced at CenterPoint
S1: ELECTRICITY-POWERED HOUSTON				
100% LDV/MDV/HDV sales electric	100% space and water heating sales electric	**Process heat** Low temp: 100% electric High temp: 70% electric, 30% H_2	**Machine drive** 90% electric **Other facility operations** 100% electric	**Green**: 1.2 Mt/yr **Blue**: 1.2 Mt/yr
S2: HYDROGEN-POWERED HOUSTON				
Mostly electric, some H_2 for MDV, HDV	100% space and water heating sales electric (slower than S1)	**Process heat** Low temp: 100% electric High temp: 50% electric, 30% H_2, 20% fossil CCS	Machine drive and other facility operations same as S11	**Green**: 1.8 Mt/yr **Blue**: 1.8 Mt/yr
S3: MIXED-FUEL				
Same as S2	Same as S2	**Process heat** Low temp: 70% electric, 30% fossil CCS High temp: 20% electric, 30% H_2, 50% fossil CCS	Machine drive and other facility operations same as S1	**Green**: 1.8 Mt/yr **Blue**: 1.8 Mt/yr

[iv] Negative emissions technologies like direct air capture operating in the Houston region would require even more clean electricity.

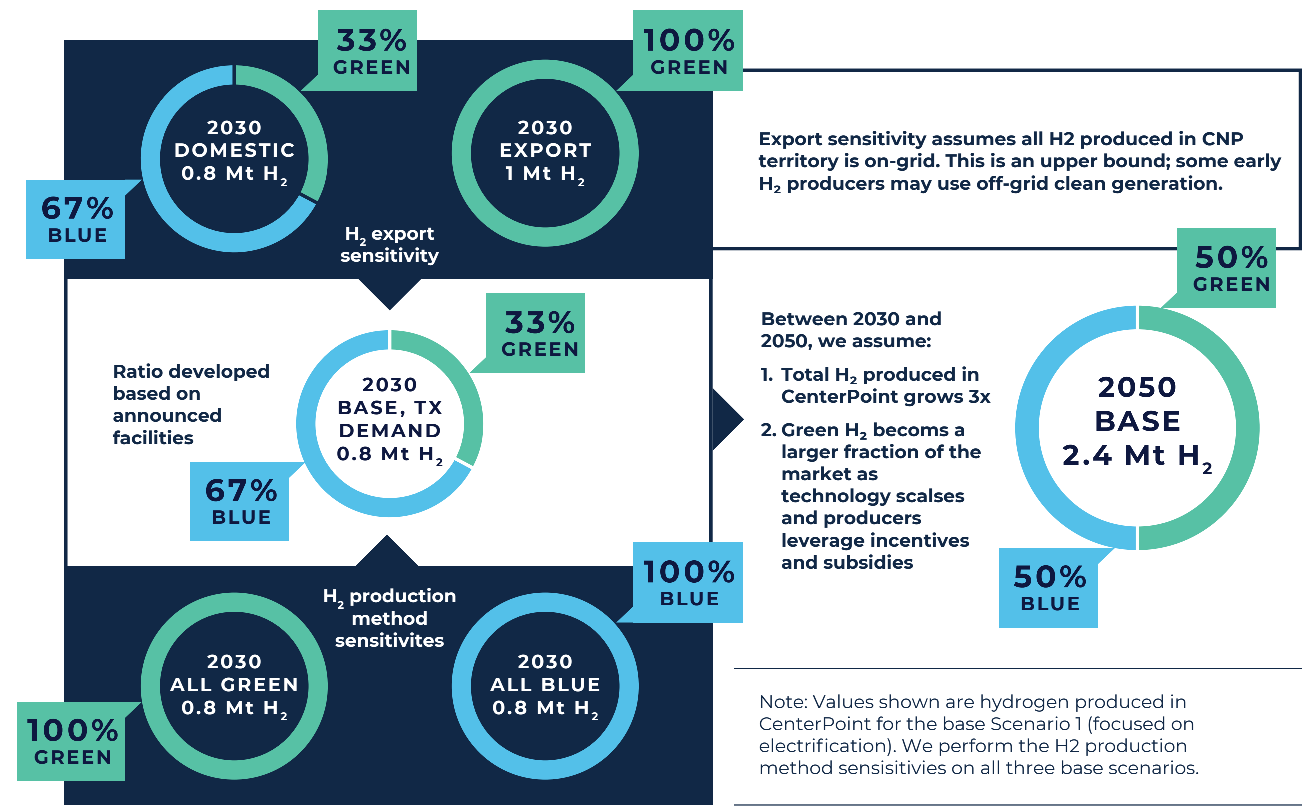
[v] **IEA WEO 2022** Net Zero Emissions by 2050 scenario; **Princeton Net-Zero America Project; Texas Energy Policy Simulator** NDC Pathway; **IEA Future of Heat Pumps** report; **Center for Houston's Future, Houston as the Epicenter of a Global Clean Hydrogen Hub report; Renewable Thermal Collaborative Vision**, Chemical Sector Pack

This analysis includes a deep dive into Houston's industrial sector. Chemicals, petrochemicals, refining, metal products, minerals, other manufacturing, and hydrogen production are examined. Adoption of industrial heat pumps and thermal energy storage or electric boilers[vi] for process heat needs is used to represent direct electrification in these sectors. This analysis does not consider demand growth from data centers, cryptomining, or the development of new manufacturing facilities driven by IRA incentives (e.g., EV battery plants), though growth in these sectors will likely also contribute to growing electricity demand.

All scenarios include the use of clean hydrogen. The base scenarios consider only hydrogen that is used in Texas, and sensitivity studies are included to explore production methods and hydrogen needed for export as outlined in Figure 5. The Center for Houston's Future's report on Houston as the Epicenter of a Global Clean Hydrogen Hub[51] is leveraged to define Texas hydrogen demand in the scenarios, with a third[vii] of this demand assumed to be produced in the CenterPoint service territory. Hydrogen production is assumed to be either blue (e.g., steam methane reforming or autothermal reforming with CCS) or green (i.e., via electrolyzers powered by renewable energy) and examine electricity needs for both. Blue hydrogen is assumed to scale faster than green initially and by 2050, half of hydrogen needed is produced via blue processes and the other half by green.

The assumptions on blue and green hydrogen are meant to evaluate potential electricity demands of both hydrogen production pathways. This report does not include an economic analysis of the two hydrogen production pathways. As mentioned in the Introduction, the IRA tax credits could influence the economics of production pathways in the future, but it will take time before impacts emerge. See the appendix for detailed information on hydrogen production in each scenario and sensitivity study.

FIGURE 5.
Summary of hydrogen production in the scenarios and sensitivity analyses



[vi] Note that thermal energy storage and electric boilers could serve similar temperature needs and they have similar efficiencies.

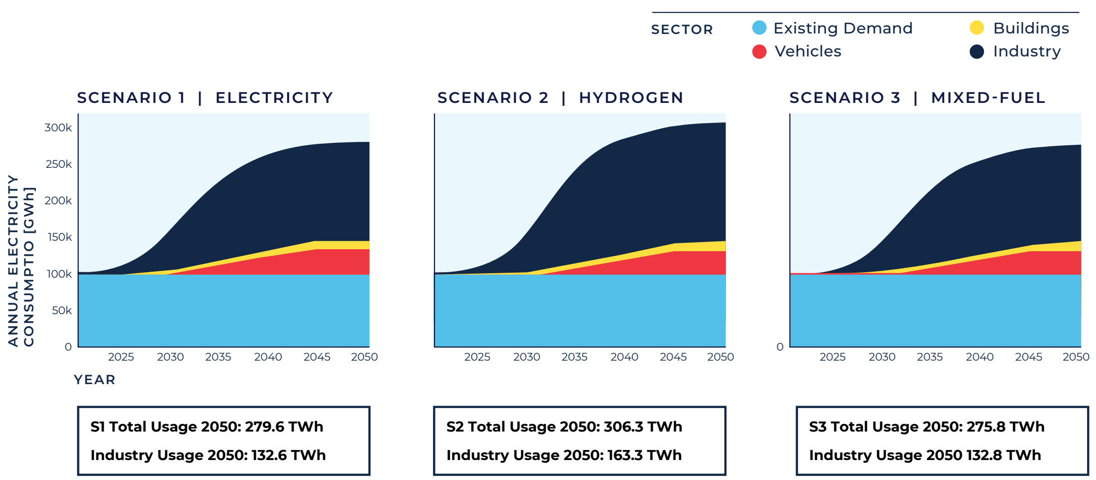
[vii] Based on announced projects in the Gulf Coast region and DOE hydrogen hub applications.

RESULTS

Finding 1: Annual electricity consumption will increase 2.75x-3x over today by 2050.

A substantial increase in total electricity consumption is calculated across the scenarios, with the smallest 2050 growth in the mixed-fuel Scenario 3 (2.75x increase) and the largest in the hydrogen-powered Scenario 2 (3x increase). Figure 6 presents area charts with forecasted total electricity consumption from 2021 to 2050. Note that in 2013, annual electricity consumption for the CenterPoint service territory was 84 terawatt-hours (TWh), which increased by 18% to reach a baseline of 99 TWh in 2021.

FIGURE 6.
Decarbonizing Houston transportation, buildings, and industry could increase electricity consumption nearly 3x by 2050 in all scenarios



While the numerical differences between these scenarios may appear relatively small, they have a substantial impact on electricity consumption. To provide perspective, average annual energy consumption of a Texas home is approximately 13 MWh per year per home[52]. The variance between the highest consumption and lowest consumption scenarios (306 TWh and 275 TWh) translates to annual electricity usage in approximately 2.4 million Texas homes. This emphasizes the significance of even minor differences in electricity consumption scenarios and their real-world implications for meeting the energy needs of households and industries.

Finding 2: Industry and hydrogen production add 40-50 TWh of demand in 2030 and 130-160 TWh in 2050. This is at least triple and at most an order of magnitude higher than the consumption of transportation and buildings combined.

The majority of new electricity consumption comes from industry and hydrogen production in the scenarios. Electricity consumption is evaluated from several industrial end uses including point source CCS, machine drive, non-process direct use (e.g., facility HVAC), process heat, blue hydrogen production, and green hydrogen production. Electrification of high temperature process heat (represented by thermal energy storage or electric boilers), along with green hydrogen production, are the major drivers in each scenario as shown in Figure 7. Green hydrogen is particularly energy intensive. Producing 1 kg of hydrogen requires about 53 kWh of electricity and its round-trip efficiency[53] is only 33%. This means that if 1 kg hydrogen is then burned again to produce electricity, it produces only 18 kWh. In many applications, electrifying directly is more efficient than burning hydrogen. This is a key reason why Scenario 1 electricity consumption from industry is lower than Scenario 2 in 2050.

Additional hydrogen production for export and methods of hydrogen production was evaluated in sensitivity analyses (Figure 8). For 2030, it is assumed that 3 million tonnes of electrolyzer processed hydrogen will be exported from Texas and produced by grid electricity. The analysis further assumed a third of this green hydrogen would be produced within CenterPoint's service territory. Using these assumptions, new industrial electricity consumption alone could double today's consumption in the CenterPoint territory by 2030.

The method of hydrogen production was varied in the sensitivity analyses, examining electricity demand in a case that assumes 100% production from blue hydrogen and another that assumes 100% green hydrogen as shown in Figure 8. For all scenarios, increasing the amount of hydrogen produced via electrolysis results in significantly higher demand. In the electricity-powered Scenario 1, industrial consumption for the 100% green case is 2.1x that of the 100% blue case. For the hydrogen-powered Scenario 2, this difference is 3x, and the difference in the mixed-fuel Scenario 3 is 4.3x.

FIGURE 7.
The majority of new consumption could come from industrial heat electrification and hydrogen production

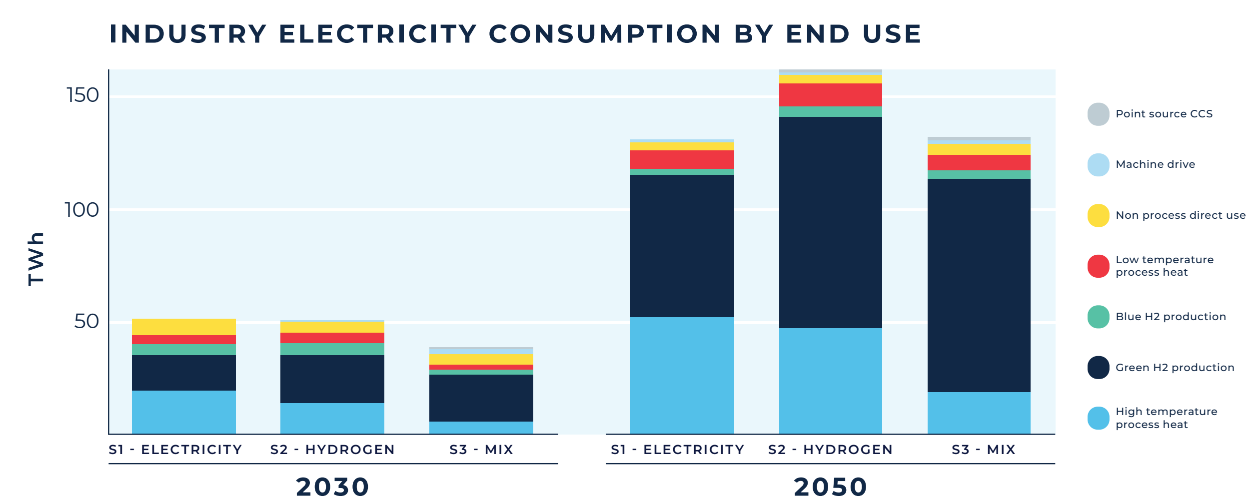
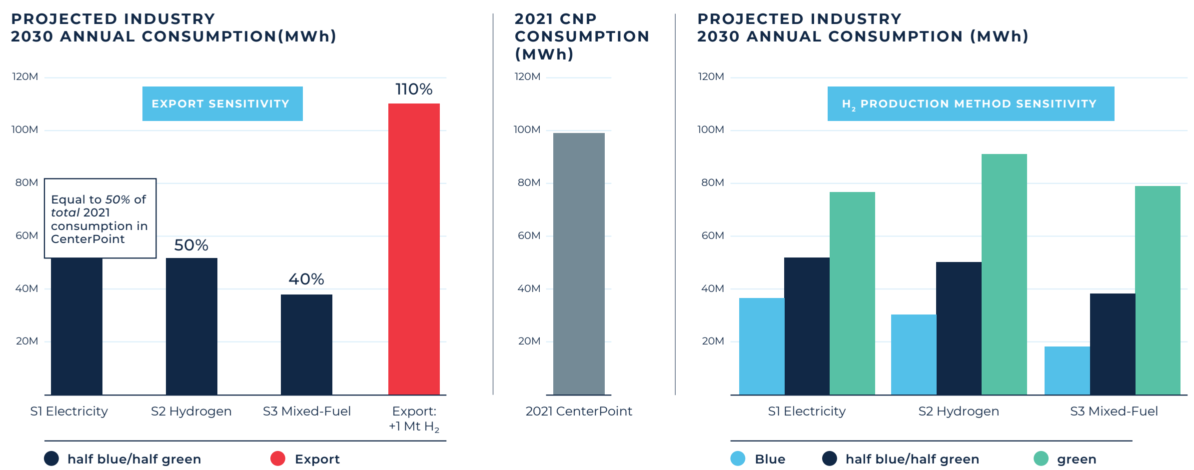
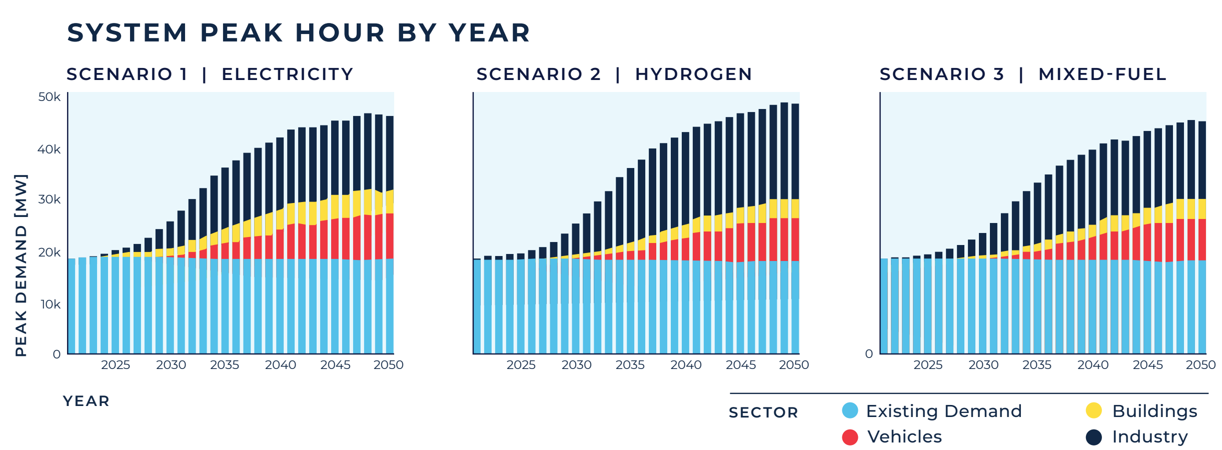


FIGURE 8.
Hydrogen could increase electricity consumption in CenterPoint (CNP) 2x by 2030 depending on production method and export needs



Finding 3: Peak demand increases 2.5x over today in all scenarios by 2050, highlighting the potential value of flexible demand.

FIGURE 9.
System peak demand could grow 2.5x in all scenarios by 2050

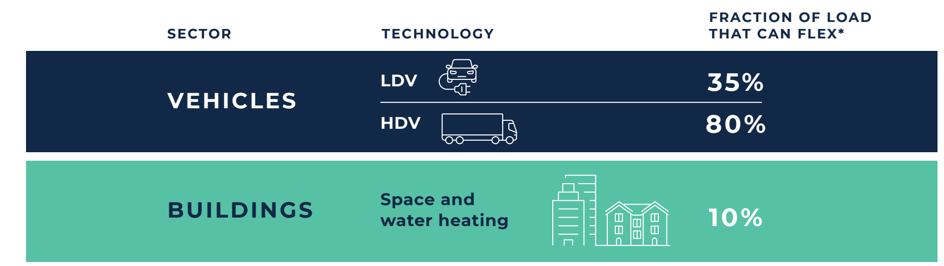


Peak demand, the highest points of electricity consumption within each year, was also evaluated. Figure 9 shows stacked bar charts, where each bar represents a snapshot of annual demand, offering insights into the forecasted peak demand for each year.

Looking ahead to 2050, relative to the baseline of 18,000 MW peak demand in 2021, all scenarios show significant growth in peak demand. Specifically, Scenarios 1 and 2, which revolve around electricity and hydrogen-based solutions, exhibit the highest peak demand, reaching approximately 49,000 MW. The mixed-fuel Scenario 3 anticipates the lowest peak demand, at around 44,000 MW.

Understanding peak demand is crucial, as these are the times of highest stress on the electrical grid. Peak demand serves as valuable input for distribution and transmission grid planning. It also provides a baseline to examine demand flexibility.

FIGURE 10.
Applying peak demand flexibility to vehicle and building devices could reduce peak demand nearly 5 GW in 2050



Peak Demand	S1: ELECTRICITY 2035	S1: ELECTRICITY 2050	S2: HYRDROGEN + S3: MIXED-FUEL 2035	S2: HYRDROGEN + S3: MIXED-FUEL 2050
Vehicle and Building Demand Before Flex	5.8 GW	13.4 GW	3.2 GW	12 GW
Vehicle and Building Demand After Flex	4.2 GW	8.6 GW	2.2 GW	7.7 GW
Demand Reduction	1.6 GW	4.8 GW	1.0 GW	4.3 GW

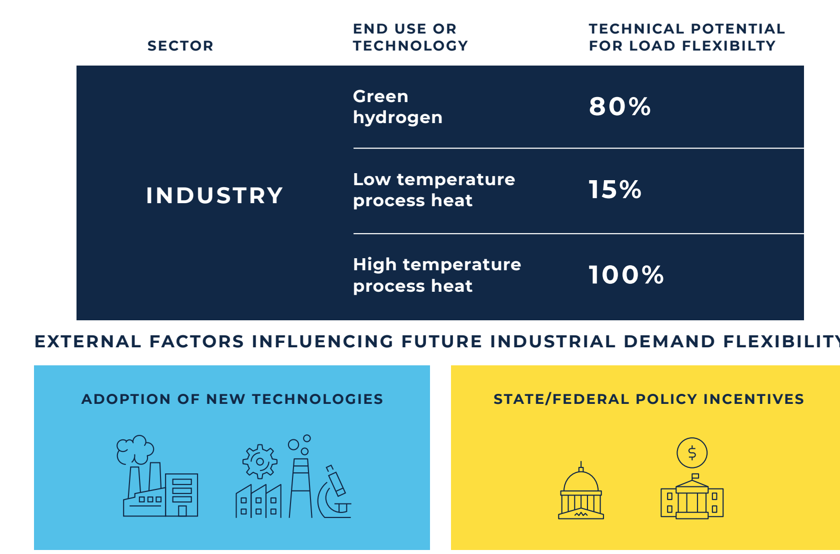
*see the appendix for additional information

Demand flexibility on the distribution system refers to the ability to shift peak demand to other time periods, effectively mitigating grid congestion and reducing the need for additional energy during peak hours. The analysis assumes demand from transport and building technologies served by the distribution system has the following flexibility percentages: 35% for light duty vehicles (LDVs), 80% for heavy duty vehicles (HDVs), and 10% across all building devices (see the appendix for more information).

Nearly 5 GW of demand could be effectively reduced by 2050 during peak hours by applying these demand flexibility percentages. This reduction offers significant relief during the most demanding days of the year.

The table in Figure 10 provides numerical before-and-after comparisons for the years 2035 and 2050, highlighting the substantial impact of demand flexibility across different scenarios. Regardless of the specific scenario considered, demand flexibility could be a powerful solution to alleviate some of the most significant challenges faced by the distribution grid during peak demand hours.

FIGURE 11.
A large portion of industrial demand could be flexible or dispatchable across all scenarios



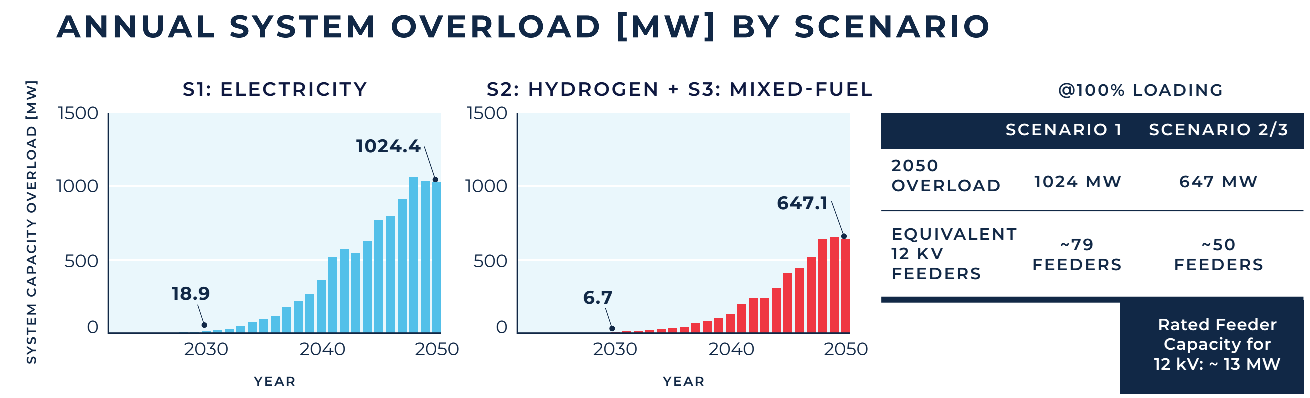
The level of dispatchability or flexibility of industrial loads that would be connected to the transmission system was examined, though further analysis is needed to consider the complexities and trade-offs between competing solutions to address peak demand. Figure 11 shows theoretical flex potential of key industrial decarbonization end uses: electrolyzers at 80%, low-temperature process heat from heat pumps at 15%, and high-temperature process heat from thermal storage at 100%.

These values cannot be applied directly to industrial peak demand data because of the nuanced nature of industrial operations. Future industrial demand could do more than simply turn on or off. Electrolyzers and thermal energy storage supplying high or low temperature heat could also respond to pricing and emissions signals, creative scheduling for grid reliability, and business optimization that ultimately reduces peak demand. In the case of thermal energy storage, process heat supply would theoretically be uninterrupted.

Finding 4: Moderate changes are needed with respect to new industrial, transportation, and buildings demand by 2030, and Houston will need to build about 10% more distribution feeders per year and make major changes to transmission system planning to meet calculated demand in 2050.

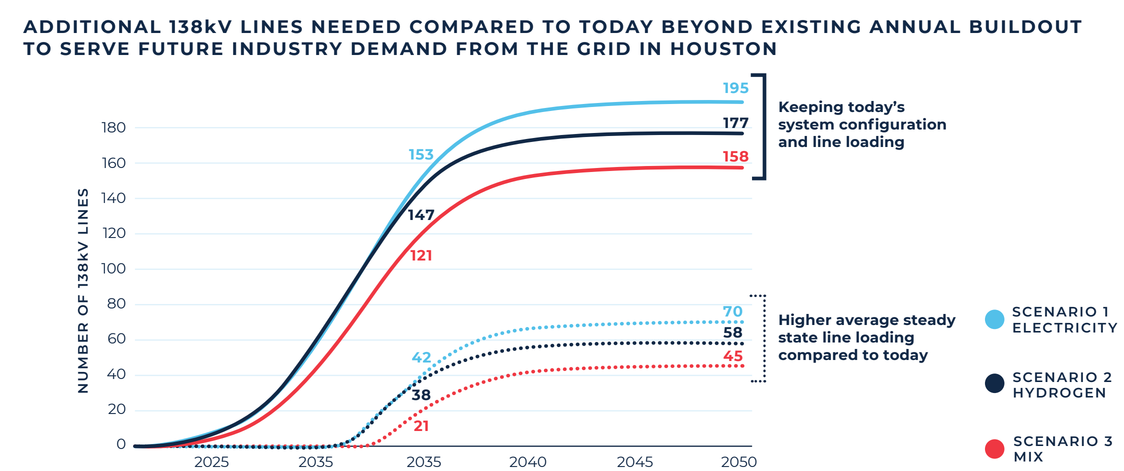
The impact of future transportation and building electricity consumption on distribution feeders is evaluated by exploring system overload in Figure 12. Distribution feeders carry electricity from substations, which step down voltage from the transmission system, to consumers (see the call-out box on page 6 for additional information). Load growth is assumed to be spread evenly across distribution feeders (a simplifying assumption, whereas in reality, feeder loading will depend on customer needs in a given area). If the feeder is loaded greater than its rate capacity, then it is considered overloaded. System capacity overload refers to the total overload across all feeders. The impact of demand flexibility, distributed generation, or energy efficiency measures like building weatherization were not considered in this analysis. Figure 12 shows that by 2030, system capacity overload is relatively small in all scenarios, requiring only one or two additional feeders. However, overload is significant by 2050 and would require 50-80 additional feeders, which translates to 10% greater buildout than what CenterPoint has been adding in recent years.

FIGURE 12.
Transportation and building electrification could require higher distribution feeder buildout per year



*Note: System capacity overload refers to the total overload across all feeders. Load growth is assumed to be spread evenly across distribution feeders (a simplifying assumption). If the feeder is loaded greater than its rated capacity, then it is considered overloaded.

FIGURE 13.
Additional 138kV lines needed compared to today beyond existing annual buildout to serve future industry demand from the grid in Houston.



Constraints to Large Tx buildout:
Limited Rights-of-way and substation sites,
138kV fault duties, distance from generation to load

Solutions:
Multi-technology approach–
higher-volatage AC Tx lines, HVDC, GETs

The number of new 138 kV transmission lines needed for each year compared to today is calculated to represent infrastructure needs to serve future industrial demand from the grid (i.e., distributed resources or behind-the-meter generation is not considered). The two boxes shown in Figure 13 align industry demand growth with the need for line expansion. Importantly, the results shown in Figure 13 do not imply that utilities must construct precisely this number of lines. The approach is simplified and does not account for various constraints such as right-of-way issues and permitting challenges, which are inherent in significant transmission buildouts. The impact of demand flexibility or behind-the-meter generation is also not considered in the analysis.

The solid lines in Figure 13 represent the number of 138 kV lines needed while maintaining the current system configuration and relatively low average steady-state loading across all scenarios. In contrast, the dotted lines indicate the number of 138 kV lines assuming higher average steady-state line loading conditions compared to the current system configuration.

The hydrogen-powered Scenario 2 with the greatest system peak demand displays the most substantial projected buildout needs by 2050. Higher line loading reduces the need for transmission buildout. However, transmission lines cannot be loaded indefinitely and should not be loaded beyond 40 to 50% on average to ensure safety, reliability, and equipment longevity.

Nevertheless, this analysis implies that more transmission capacity is needed to serve decarbonized industrial demand. In reality, there are many constraints to transmission buildout in Houston, including limited sites for rights-of-way and substations, line fault duties, and distance from generation to load. Besides the 138 kV lines evaluated in this analysis, technologies such as higher voltage AC lines, HVDC lines, or the implementation of grid enhancing technologies (GETs) could help meet demand. Additionally, more hydrogen could be produced elsewhere and transported to the Houston region via pipeline. These alternatives offer avenues to optimize the grid and potentially reduce the extensive transmission buildout required to meet industrial demand growth.

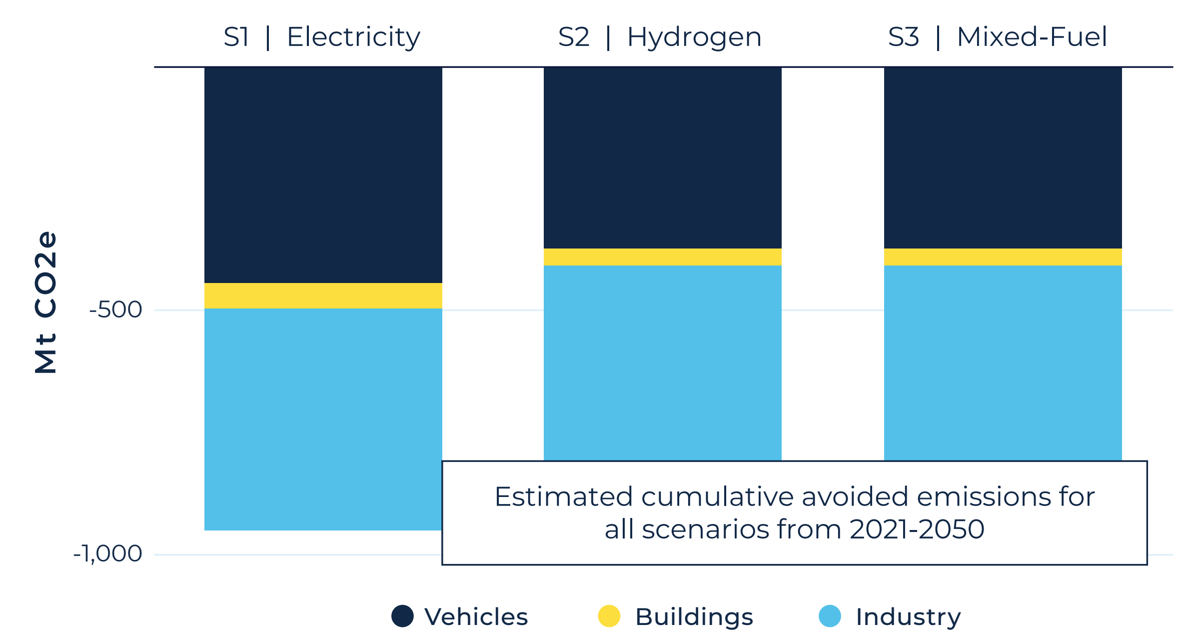
Finding 5: Houston avoids at least 0.8 Gt CO_2e cumulative emissions over 2021-2050 in all scenarios.

Technology deployment varies across scenarios, leading to different levels of avoided GHG emissions. The analysis estimates cumulative avoided GHG emissions from 2021 to 2050 by looking at all decarbonization technologies and processes in each year. This analysis first considers the emissions in a sector with technologies and processes powered by fossil fuels. For example, new light-duty vehicles are powered by gasoline, and high-temperature process heat is fueled by natural gas. Fossil-powered emissions are then compared to the scenario emissions. For example, a certain portion of new light-duty vehicles in each scenario year will be electrified, and some high-temperature process heat will be converted to hydrogen and have lower emissions. As shown in Figure 14, the electricity-powered Scenario 1 has 15% greater potential for avoided emissions compared to Scenarios 2 and 3 due to a combination of factors including faster transport electrification, less reliance on CCS, and lower blue hydrogen production.[viii]

While detailed evaluations of emerging issues impacting GHG emissions management were outside the scope of this analysis, additional investigations could address important considerations such as full lifecycle analysis of GHG emissions and trade-offs for each decarbonization and electrification technology solution. Additionally, further investigation of the impact of hydrogen leakage during hydrogen production is recommended to address an emerging issue that could become increasingly important as regional hydrogen hubs develop. A full evaluation of air pollution impacts resulting from electrification of large industrial processes, vehicles, and building heating could address mitigation of localized pollution for Houston residents living near large industrial and densely populated urban areas.

[viii] It is assumed CCS and blue hydrogen production exhibit some leakage.

FIGURE 14.
Estimate of cumulative avoided GHG emissions from 2021-2050 for all scenarios



APPROACH

Stock rollover modeling is combined with industrial end use energy demand evaluation, grid infrastructure calculations, and GHG emissions reduction methods in this analysis. See the appendix for a detailed explanation of the approach.

ELECTRICITY CONSUMPTION, PEAK DEMAND, AND DEMAND FLEXIBILITY

A stock rollover model was used to estimate electricity consumption and hourly demand for buildings and transportation. Stock rollover models[54] use estimated future sales of electric devices (e.g., medium-duty vehicles) and growth data (e.g., population growth) to calculate the evolving makeup of the device stock (electric versus other, either fossil or hydrogen) through time. Under each scenario the number of electric transport and building devices deployed in Houston in future years is calculated. The device stock data is then combined with average hourly load profiles by device to calculate the total load. See the appendix for more information on scenario assumptions for transport and buildings device sales and load.

Electricity consumption and capacity demand are calculated separately for the industrial sector. Emissions from existing facilities, reported annually to the EPA[55], are used as a proxy for energy demand today. Natural gas powers most processes, and therefore emissions are assumed to provide a proxy for natural gas demand, applying assumptions on future economic growth. Efficiency assumptions are used to translate natural gas demand to electricity consumption. To calculate capacity demand, all industrial loads are assumed flat and total industrial consumption will evolve on an s-curve.

Peak hourly demand is determined by examining new load from buildings, transport, and industry as well as existing CenterPoint demand in each hour of the year, by identifying the hour with the highest total load. The analysis explores the potential for demand flexibility to reduce peak load across various technologies, considering different sectors and their respective capabilities. Note that the analysis only explores the potential magnitude of demand flexibility, and does not consider demand flexibility in the grid infrastructure impacts analysis.

GRID INFRASTRUCTURE IMPACTS

Future grid infrastructure needs were evaluated based on annual peak system demand and available capacity. The distribution and transmission systems were examined separately. CenterPoint serves transportation and building loads via the distribution system and most large industrial loads via higher voltage lines directly through the transmission system.

The magnitude of distribution system overload from transport and building loads was calculated by examining demand data of feeders in the CenterPoint system today, future demand from transport and buildings, and the existing annual feeder buildout rate. Infrastructure needed to serve industrial load growth in Houston's existing industrial zones (see Figure 15) was examined, with focus on how many 138 kV transmission lines would be needed in 2050 considering future industry electricity demand and CenterPoint's existing line buildout rate. All load is assumed to be met from the grid, and the analysis does not consider the impact of distributed energy resources or large-scale behind-the-meter generation.

AVOIDED GHG EMISSIONS

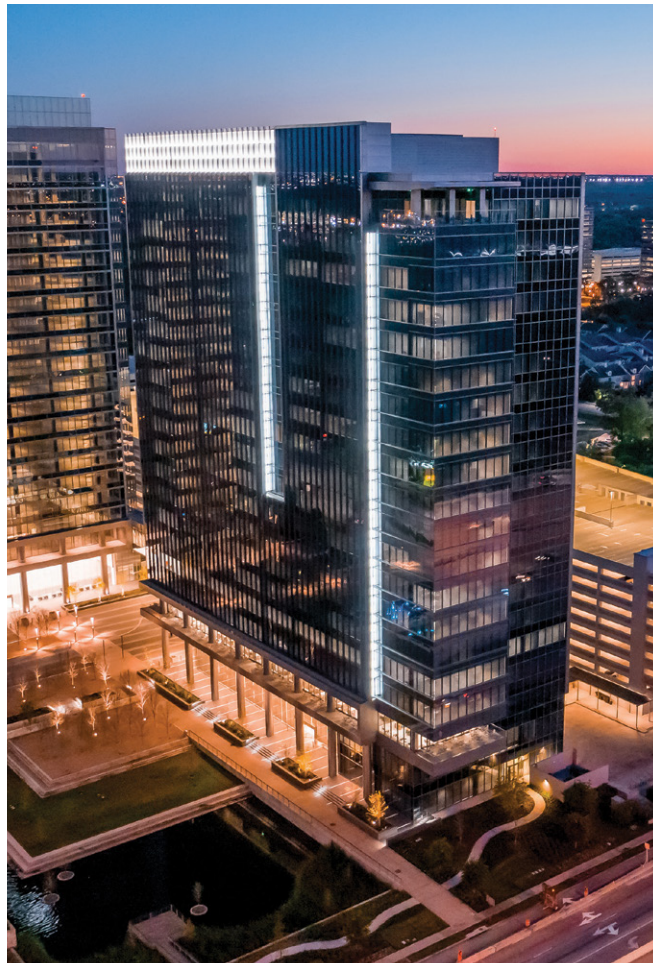
Avoided GHG emissions across all sectors is estimated, acknowledging that full life cycle analyses of GHG emissions and trade-offs for each decarbonization technology are important factors that should be studied in further detail. Avoided GHG emissions are defined as the difference between scenario emissions and fossil fuel powered emissions. Scenario emissions are calculated by considering each decarbonization solution, evolving grid emissions intensity, and potential leakage from CCS and blue hydrogen production. Fossil fuel powered emissions are calculated based on the fossil alternatives to each transport and buildings decarbonization solution plus emissions from natural gas demand in the absence of decarbonization in industry. Several critical assumptions aid these calculations:

- The ERCOT Long-Term System Assessment is used to define grid emissions intensity in the 2030s, and grid emissions are assumed to be zero in 2050.
- Hydrogen produced by electrolyzers and high-temperature heat supplied by thermal energy storage or electric boilers is assumed to be powered by zero carbon electricity.
- 10% leakage from CCS systems is assumed (typical[56] for analyses like this).

FIGURE 15.
Existing industry zones in the CenterPoint service territory

PART 06

HOW HOUSTON CAN SUPPORT A SUSTAINABLE, RESILIENT, AND LOW-CARBON ELECTRICITY GRID



Industry, especially hydrogen production, will be an important driver for electricity growth in Houston through the energy transition. The scenarios analyzed, which aim to fully implement decarbonization solutions across sectors by 2050, estimate 50% growth in electricity consumption by 2030 and nearly a tripling in consumption by 2050 across the CenterPoint service territory.

The region's pathway to decarbonization is of course uncertain, and the scenarios evaluated in this report are not meant to be a forecast.

Expanding the electricity grid to support this growth, with support from additional solutions such as demand flexibility, energy efficiency, and distributed generation, will help Houston seize the opportunity of the energy transition while decarbonizing transport, buildings, and industry.

The scale of electrical grid infrastructure buildout implied by the scenarios is massive but not entirely unprecedented in the state. Texas has done this before with the help of policy, market redesign, and transmission buildout.[57] Legislative action established a state renewable portfolio standard (RPS) in 1999.[58] A subsequent law, SB20, increased RPS ambition in 2005 and directed the Public Utility Commission of Texas (PUCT) to establish Competitive Renewable Energy Zones (CREZ).[59] which ultimately aided in the construction of 3600 miles[60] of new transmission in the state by 2014.

From 2013-2022, ERCOT generation[61] grew 30% overall and on average around 3.5% per year. Electricity consumption in the CenterPoint service territory grew between 1-5% per year in the last decade. In comparison, average annual electricity consumption growth today to 2030 is 4-5% per year in the scenarios evaluated, and 3-3.5% per year 2031-2050. Most of the ERCOT growth in the last decade was from solar and wind generation[62]. Today, ERCOT leads other regions, RTOs, and ISOs with installed wind, solar, and storage on a capacity basis at around 40 GW. Installed solar capacity in the state is expanding and as of Q4 2022, Texas had more solar in interconnection queues than any other state.[63]

Demand flexibility, maximizing energy efficiency, and utilizing distributed generation across all sectors are complementary levers to help manage system costs and reliability. Around 30% of distribution system demand from transport and buildings could be flexible in 2030, and around 60% of industrial load would be technically dispatchable (though considering economics would likely show a different percentage). Clean peaking capacity and storage could help alleviate grid stress. New transmission and distribution technologies could be adopted to make the current grid more efficient or expand grid capacity at lower cost. Energy efficiency across all sectors, such as building weatherization and industrial process optimization, can help reduce system peak capacity demand. Finally, generation located near load, from sources such as rooftop solar and large-scale behind-the-meter generation for industrial load, may help alleviate grid stress. A recent report from the Energy Systems Integration Group (ESIG) found that greater buildout of distributed energy resources like rooftop solar and batteries installed behind the meter and homes and businesses results in a decrease in inter-zonal transmission needs in the United States' Western Interconnection.[64] Given the complexities of the grid, further analysis is needed to explore the impact of demand flexibility, energy efficiency, and distributed generation in greater detail.


Given the potential for enormous growth in demand, key stakeholders in the region should proactively prepare for the possibility of additional generation, grid expansion, demand-side management, and energy efficiency as options to meet increased demand.

While market forces and public incentives certainly play a role in decarbonization, decisive action by Houston's businesses, policymakers, and consumers also determine the path forward for investments in grid infrastructure that could capture the business opportunities associated with energy transition. Corporations could proactively signal their interest in electricity-powered solutions to their utilities, considering the long lead time for grid infrastructure (approximately 10 years) and long-term business cycles. Utilities, ERCOT, PUCT, and policymakers could plan more proactively with a deeper dive into load growth from industry, and consumers should be actively involved in making the grid more reliable and affordable.

Utilities, ERCOT, PUCT, and policymakers can also plan more proactively. These stakeholders could take a deeper dive into load growth, especially from industry, and begin discussions on how best to equitably finance new grid infrastructure. Proactive planning and inventive market design could also involve creating favorable conditions to leverage the demand flexibility and dispatchability of new electrified loads while aiding reliability and emissions reductions. Customers should be part of this conversation, as they will need incentives and transparency to actively participate in making the grid more reliable and to save themselves money.


Prioritizing decarbonization strategies in Houston reliant on electricity could offer significant economic benefits and contribute to reducing GHG emissions and air pollutants in the region.

While there is uncertainty in the long-term growth of electrification in Houston, many options exist to meet increased peak demand by 2050. The scenarios in this analysis focused on electricity demand growth from moderately aggressive growth in low-carbon solutions for industry, transportation, and buildings within the CenterPoint territory. If grid infrastructure investments are needed to meet this possible increased demand, these scenarios provide preliminary insights into grid infrastructure needs within the CenterPoint territory in Houston. Given the uncertainty and potential for enormous growth in electricity demand in Houston, additional analyses are needed to explore the complexities of the power system and develop supply-side insights for scenarios to meet peak electricity demand in Houston by 2050.

PART 07

APPENDIX

Numeric results

2030

METRIC (UNITS)	SCENARIO	S1: ELECTRIFICATION	S2: H_2-POWERED	S3: MIXED FUELS
Total Energy Usage (GWh)	**Total**	**153,001**	**151,984**	**139,942**
	Vehicles	1933	789	789
	Buildings	3596	1368	1368
	Industry	48,136	50,492	38,449
Total Peak Demand (MW)	**Total**	**25,922**	**25,198**	**23,823**
	Vehicles	385	161	161
	Buildings	1251	483	483
	Industry	5495	5764	4389

2030

METRIC (UNITS)	BASE SCENARIO	ALL BLUE H_2	ALL GREEN H_2	EXPORT
Total industry energy usage in sensitivity studies (GWh)	S1: Electrification	36,595	76,995	110,519
	S2: H_2 - powered	30,292	90,892	N / A
	S3: Mix	18,249	78,849	N / A

2050

METRIC (UNITS)	SCENARIO	S1: ELECTRIFICATION	S2: H_2-POWERED	S3: MIXED FUELS
Total Energy Usage (GWh)	**Total**	**279,653**	**306,327**	**275,836**
	Vehicles	35,565	33,434	33,434
	Buildings	12,139	10,221	10,221
	Industry	132,613	163,336	132,845
Total Peak Demand (MW)	**Total**	**46,734**	**48,904**	**45,423**
	Vehicles	8,782	8,164	8,164
	Buildings	4,585	3,866	3,866
	Industry	15,138	18,646	15,165
Cumulative GHG reduction 2021 - 2050 compared to business as usual (Mt Co_2)	**Total**	948	821	825
	Vehicles	443	375	375
	Buildings	53	35	35
	Industry	452	412	415

Scenario detail

TABLE A.
SUMMARY OF KEY SCENARIO VARIABLES BY SECTOR AND TECHNOLOGY

SECTOR	TECHNOLOGY OR END USE	PRIMARY SCENARIO VARIABLE	NOTES
Transportation	Light-duty vehicles (LDV), medium-duty vehicles (MDV), and heavy-duty vehicles (HDV)	% of total vehicle sales that are electric	Hydrogen-powered vehicles are considered in Scenarios 2 and 3
Buildings	Space heating, water heating	% of total space and water heating sales that are electric	
Industry	Process heat, machine drive, other facility needs (e.g., office HVAC)	% of total energy demand that is electric, hydrogen-powered, or utilizing point-source CCS	
	Low emissions hydrogen production	Mt (million tonnes) produced	Blue (e.g., steam methane reforming or autothermal reforming with CCS) and green (electrolyzers powered by renewable energy) production pathways are considered

TABLE B1.
ALL SCENARIO VARIABLES – SCENARIO 1, ELECTRICITY-POWERED HOUSTON

TECHNOLOGY OR END USE	PRIMARY SCENARIO VARIABLE	2035 VALUE (LDV) 2030 VALUE (ALL OTHER TECHNOLOGIES AND END USES)	2050 VALUE
LDV	% of total device sales that are electric	100%	100%
MDV	% of total device sales that are electric	30%	100%
HDV	% of total device sales that are electric	30%	100%
Building space heating	% of total device sales that are electric	100%	100%
Building water heating	% of total device sales that are electric	100%	100%
Industry process heat (low temperature)	% of total energy demand that is electric	40%	100%
Industry process heat (high temperature)	% of total energy demand that is electric	28%	70%
Industry machine drive	% of total energy demand that is electric	36%	90%
Other industry end uses	% of total energy demand that is electric	100%	100%
Industry process heat (low temperature)	% of total energy demand that is hydrogen-powered	0%	0%
Industry process heat (high temperature)	% of total energy demand that is hydrogen-powered	3%	30%
Industry process heat (low temperature)	% of total energy demand that utilizes point-source CCS	0%	0%
Industry process heat (high temperature)	% of total energy demand that utilizes point-source CCS	0%	0%

TABLE B2.
ALL SCENARIO VARIABLES – SCENARIO 2, HYDROGEN-POWERED HOUSTON

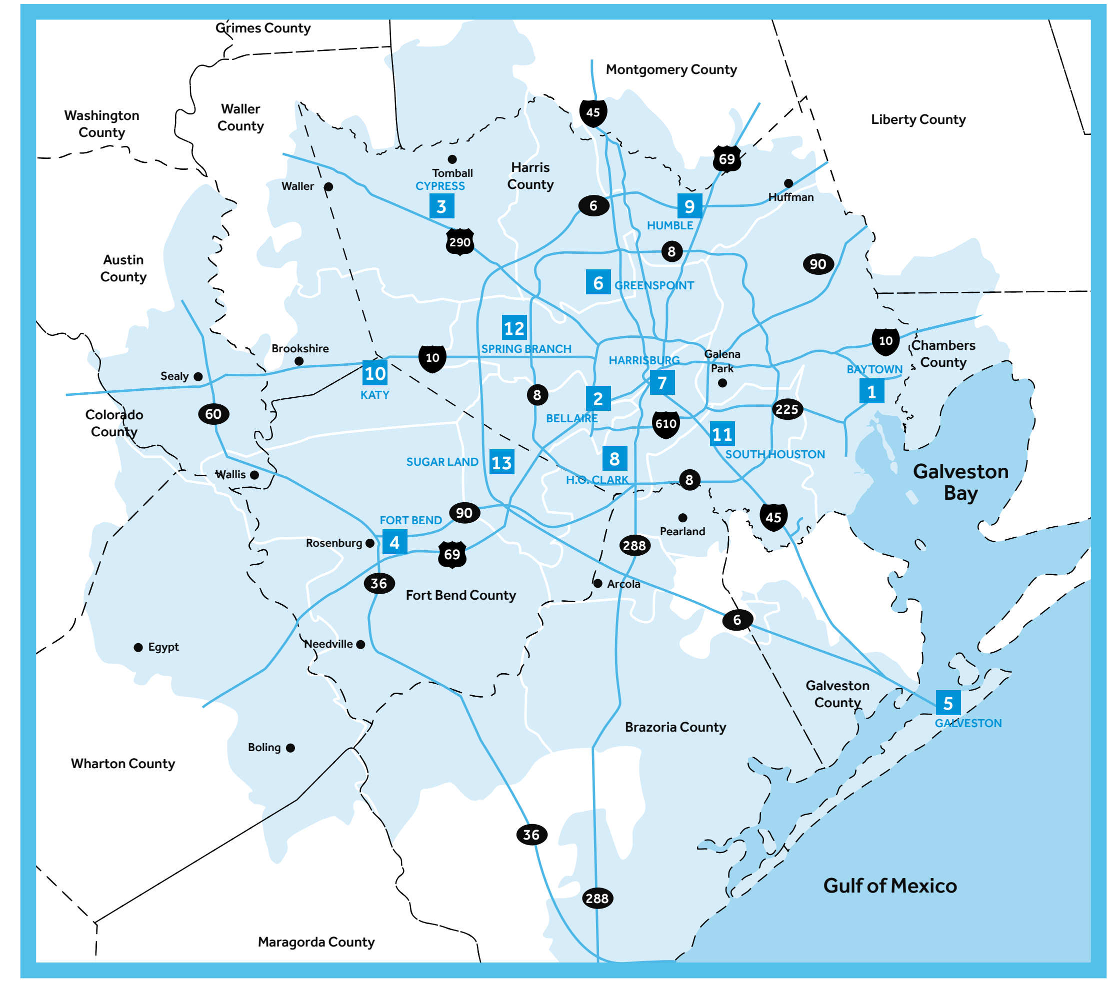
TECHNOLOGY OR END USE	PRIMARY SCENARIO VARIABLE	2035 VALUE (LDV) 2030 VALUE (ALL OTHER TECHNOLOGIES AND END USES)	2050 VALUE
LDV	% of total device sales that are electric	80%	100%
MDV	% of total device sales that are electric	30%	92%
HDV	% of total device sales that are electric	30%	92%
Building space heating	% of total device sales that are electric	75%	100%
Building water heating	% of total device sales that are electric	75%	100%
Industry process heat (low temperature)	% of total energy demand that is electric	40%	100%
Industry process heat (high temperature)	% of total energy demand that is electric	20%	50%
Industry machine drive	% of total energy demand that is electric	36%	90%
Other industry end uses	% of total energy demand that is electric	100%	100%
Industry process heat (low temperature)	% of total energy demand that is hydrogen-powered	0%	0%
Industry process heat (high temperature)	% of total energy demand that is hydrogen-powered	3%	30%
Industry process heat (low temperature)	% of total energy demand that utilizes point-source CCS	0%	0%
Industry process heat (high temperature)	% of total energy demand that utilizes point-source CCS	8%	20%

TABLE B3.
ALL SCENARIO VARIABLES – SCENARIO 3, A MIX OF FUELS FOR HOUSTON

TECHNOLOGY OR END USE	PRIMARY SCENARIO VARIABLE	2035 VALUE (LDV) 2030 VALUE (ALL OTHER TECHNOLOGIES AND END USES)	2050 VALUE
LDV	% of total device sales that are electric	80%	100%
MDV	% of total device sales that are electric	30%	92%
HDV	% of total device sales that are electric	30%	92%
Building space heating	% of total device sales that are electric	75%	100%
Building water heating	% of total device sales that are electric	75%	100%
Industry process heat (low temperature)	% of total energy demand that is electric	28%	70%
Industry process heat (high temperature)	% of total energy demand that is electric	8%	20%
Industry machine drive	% of total energy demand that is electric	36%	90%
Other industry end uses	% of total energy demand that is electric	100%	100%
Industry process heat (low temperature)	% of total energy demand that is hydrogen-powered	0%	0%
Industry process heat (high temperature)	% of total energy demand that is hydrogen-powered	3%	30%
Industry process heat (low temperature)	% of total energy demand that utilizes point-source CCS	12%	30%
Industry process heat (high temperature)	% of total energy demand that utilizes point-source CCS	20%	50%

CenterPoint service territory coverage

From https://www.centerpointenergy.com/en-us/Services/Pages/electric-transmission-and-distribution.aspx?sa=HO&au=bus



Industry load impact methodology

Abbreviations, definitions, and notes

t CO_2 = metric tonnes CO2

t = metric tonnes

Mt = million metric tonnes

mmbtu = million metric British thermal units

mbtu = metric British thermal unit

MWh = megawatt hour

kWh = kilowatt hour

Note: Presently, these calculations are within in the CenterPoint service territory only. See pg 5 for a map.

Direct electrification electricity demand

CALCULATING NATURAL GAS ENERGY DEMAND FROM EMISSIONS

Natural gas energy demand (energy_ng) is calculated based on facility stationary combustion emissions (emissions_sc, see Assumption 1) and the EPA's emission factor for stationary combustion of natural gas:

$$energy_{ng}\ [mmbtu] = emissions_{sc}\ [t\ CO_2] * \frac{1000\ [kg]}{1\ [t]} * [\frac{mmbtu}{53\ kg\ CO_2}]$$

CALCULATING NATURAL GAS ENERGY DEMAND BY END USE, STEP 1

EIA 2018 MECS data Table 5.2 "Energy Consumed as a Fuel by End Use" for each facility's NAICS code is used to calculate energy demand from three main end uses electrified to various degrees in the scenarios:

- Process heat: 84% of "CHP and/or Cogeneration Process" (see Assumption 2) + Conventional Boiler Use + Process Heating
- Nonprocess direct use: 16% of "CHP and/or Cogeneration Process" (see Assumption 2) + Facility HVAC + Facility Lighting + Other Facility Support + Conventional Electricity Generation + Other Nonprocess Use
- Machine Drive

The percent of total energy demand for each of these end uses is calculated (perc_process_heat_total, perc_nonprocess_direct_use, perc_machine_drive). Each percentage is then multiplied by energy_ng to get energy from natural gas for each end use (energy_from_ng_process_heat_total, energy_from_ng_nonprocess_direct_use, energy_from_ng_machine_drive)

$$energy\ from\ ng\ process\ heat\ total\ [mmbtu] = perc\_process\_heat\_total * energy\_ng[mmbtu]$$

$$energy\ from\ ng\ nonprocess\ direct\ use\ [mmbtu] = perc\_nonprocess\_direct\_use * energy\_ng[mmbtu]$$

$$energy\ from\ ng\ machine\ drive\ [mmbtu] = perc\_machine\_drive * energy\_ng[mmbtu]$$

SECTOR AGGREGATION

Facility emissions are aggregated into five main sectors:

- Chemical production (NAICS code beginning with 325) with cracker
- Chemical production without cracker
- Refineries (NAICS code beginning with 324110) with cracker
- Refineries without cracker
- Other (in CenterPoint, this is a few metal production manufacturers, a glass manufacturer, and a brewery)

For more information on the sectors with cracker, see Assumption 3.

All end use energy from natural gas values, as well as steam cracker capacity (steam_cracker_capacity) is added by sector.

CALCULATING NATURAL GAS ENERGY DEMAND BY END USE, STEP 2 (FINALIZING PROCESS HEAT)

Steam cracker natural gas energy demand is calculated based on capacity and energy intensity (from Table 3 of Chung et al).

$$energy\_from\_ng\_process\_heat\_steamcracker[mmbtu] = steam\_cracker\_capacity\ [\frac{Mt\ ethylene}{yr}] * 16.3\ [\frac{GJ}{t\ ethylene}] * [\frac{1e9\ J}{GJ}] * [\frac{1e6\ t}{Mt}] * \frac{1\ mbtu}{1055\ J} * \frac{1\ mmbtu}{1e6\ mbtu}$$

Total process heat natural gas energy demand is split into temperature, <100C and >100C (see Assumption 4).

$$energy\_from\_ng\_process\_heat\_lt100\_hp\ [mmbtu] = 0.23 * energy\_from\_ng\_process\_heat\_total[mmbtu]$$

$$energy\_from\_ng\_process\_heat\_gt100[mmbtu] = 0.77 * energy\_from\_ng\_process\_heat\_total[mmbtu]$$

Steam cracker energy demand from process heat >100C energy demand is then subtracted to get high temperature heat that could be decarbonized with thermal energy storage/electric boilers (energy_from_ng_process_heat_gt100_tes).

$$energy\_from\_ng\_process\_heat\_gt100\_tes\ [mmbtu] = energy\_from\_ng\_process\_heat\_gt100[mmbtu] - energy\_from\_ng\_process\_heat\_steamcracker[mmbtu]$$

CALCULATING ELECTRICITY DEMAND FROM DIRECT ELECTRIFICATION

There are five main components to the electricity demand calculation:

- **Energy demand from natural gas for the following end uses**
  - Process heat, which are split by temperature and technology:
    - Less than 100C: electrified by a heat pump
    - Greater than 100C: mostly electrified by thermal energy storage or electric boilers. Note that both technologies have similar efficiencies and so are interchangeable for the purposes of this analysis. Where a sector includes steam crackers, process heat >100C was further split and assumed to be electrified
  - Nonprocess direct use
  - Machine drive
- **Sector growth/shrink, (variable "growth") per year. See Assumption 5 for additional information**
- **Percent electrification in the future year defined by scenario (p_demand_elec_2030 and p_demand_elec_2050)**
- **Natural gas end use efficiency (ng_eff) and electric end use efficiency (elec_eff)**
  - Both natural gas and electric end use efficiency are needed. Calculated natural gas energy demand from emissions is based upon the amount of natural gas a facility might use, i.e. from its utility bill. This is how some facilities report their emissions to EPA (see Tier 1 and 2 explanation here).
  - As shown below, Natural gas energy demand is multiplied first by natural gas efficiency, giving the amount of useful energy used for the process.
  - That value is then divided by the electric efficiency, which accounts for losses involved with using the device.
  - See Assumption 6 for assumptions on natural gas and electric device efficiencies.

Electricity demand in 2030 and 2050 is calculated by scenario for all end uses:

$$elec\_demand_{2030}\ [MWh]$$

$$= nergy\_from\_ng(end\ use)[mmbtu] \ * \ (1+growth\left[\frac{\%}{yr}\right]) * (2030\text{-}2021)$$

$$* \ p\_demand\_elec\_2030 \ * \left[\frac{ng_{eff}}{elec_{eff}}\right] * \left[\frac{0.293\ MWh}{mmbtu}\right]$$

Hydrogen production electricity demand

Hydrogen production by scenario is based on the hydrogen report published by HETI and Center for Houston's Future. The table below shows total production numbers from the report for Texas and what assume is produced in the CenterPoint service territory for each scenario and sensitivity study.

TABLE C.
HYDROGEN PRODUCTION BY SCENARIO

SCENARIO	TEXAS H2 PRODUCTION IN 2050 (MT/YR)	CENTERPOINT H2 PRODUCTION IN 2050 (MT/YR)
Scenario 1: Electricity-powered Houston	11.8	5.6
Scenario 2: Hydrogen-powered Houston	21	10.5
Scenario 3: Mixed fuels	20	10

Blue hydrogen is assumed to scale faster than green initially and by 2050, production method is split evenly in the core scenarios and production method sensitivities. In the export sensitivity, it is assumed all hydrogen produced for export is green based on EU regulations. The table below shows CenterPoint blue and green hydrogen production by scenario and year.

TABLE D
HYDROGEN PRODUCTION BY YEAR, SCENARIO, AND PRODUCTION METHOD IN CENTERPOINT

SCENARIO OR SENSITIVITY CASE	YEAR	BLUE HYDROGEN PRODUCTION (MT)	GREEN HYDROGEN PRODUCTION (MT)
Scenario 1	2030	0.5	0.3
	2050	1.2	1.2
Scenarios 2 and 3	2030	0.8	0.4
	2050	1.8	1.8
Scenario 1 – all blue	2030	0.8	0
	2050	2.4	0
Scenario 1 – all green	2030	0	0.8
	2050	0	2.4
Scenarios 2 and 3 – all blue	2030	1.2	0
	2050	3.6	0
Scenario 2 and 3 – all green	2030	0	1.2
	2050	0	3.6
Scenario 1 with hydrogen for export	2030	0.5	1.3
	2050	1.2	6.2

Electricity demand for hydrogen in a future year is based on annual production in that year and the electricity intensity of hydrogen.

$$h2\_elec\_demand2030\ [MWh]$$

$$= annual\_production\_2030 \left[\frac{Mt\ H2}{yr}\right] * elec\_intensity \left[\frac{kWh}{kg\ H2}\right] * \frac{1000\ kg\ H2}{t\ H2} * \left[\frac{1e6\ t\ H2}{Mt\ H2}\right] * \left[\frac{1\ MWh}{1000\ kWh}\right]$$

Point-source CCS (beyond what's used for blue H2) electricity demand

One scenario included considers part of industrial process heat still powered by fossil fuels (p_demand_ccs_2030 and 2050) but the facility has its own point-source CCS. In this scenario, process heat emissions is scaled up based on the sector growth/shrink assumptions in each scenario. An electricity intensity of capturing CO2 is then used to calculate electricity demand for the point-source CCS systems.

$$ccs\_elec\_demand\_2030[MWh]$$

$$= missions\_end\_use[t\ CO2] * \left(1+growth\left[\frac{\%}{yr}\right]\right) * (2030\text{-}2021) * p\_demand\_elec\_2030 * cs\_elec\_intensity \left[\frac{MWh}{t\ CO2}\right]$$

Preliminary results

To compare these results to the size of CenterPoint's current system, MWh are converted to MW. To do this, all industrial loads are assumed flat, i.e. they run constant 24 hours a day 7 days a week. This is an ultra-simplified assumption, especially for thermal energy storage and for the future prospect of running hydrogen electrolyzers flexibly. However, the analysis seeks an order magnitude to compare to CenterPoint's system. These assumptions are emphasized in the final documentation.

$$MW\ demand = \frac{MWh\ from\ end\ uses}{yr} * \frac{yr}{8760\ hrs}$$

Assumptions

1. All stationary combustion emissions are assumed to be from burning natural gas. Table 3.2 of EIA 2018 MECS shows that chemical production and refining sectors relevant for the analysis get >90% of their fossil energy from natural gas or "Other". The EPA FLIGHT tool shows "Other" appears to be mostly fuel gas for facilities in the CenterPoint service territory, which according to the EPA GHG Emissions Factor Hub has a very similar emissions factor to natural gas (53 kg CO2/mmbtu natural gas vs 59 kg CO2/mmbtu fuel gas).

2. 84% of energy for CHP and/or cogeneration process from EIA 2018 MECS data Table 5.2 is assumed to be used to make steam and 16% is used for electricity. This is based on the useful energy (excluding losses) in the Onsite Generation DOE Sankey Diagrams of 2014 MECS data.

3. Several facilities with crackers have been identified. This may not be comprehensive of all facilities that have crackers in the area. This is a conservative estimate, resulting in a scenario that requires higher electricity demand as thermal energy storage and electric boilers are more efficient than an electric cracker.

4. 23% of total energy demand for process heat is assumed <100C and 77% is >100C. This is aligned with data on the chemical industry in Europe (see Figure 6 of this Renewable Thermal Collaborative report). This also aligns with total global process heat demand across all industries according to the IEA's report on the Future of Heat Pumps (see Figure 1.16).

5. Sector growth/shrink assumptions are as follows.

    a. The refinery sectors shrink depending on scenario given differing levels of vehicle electrification. For the high electrification scenario, the sector is assumed to get smaller by 4.5% per year. This reflectes the reduction in annual global oil supply from now to 2050 in the IEA's Net Zero scenario from the 2022 World Energy Outlook. For the other scenarios that are more focused on decarbonization through hydrogen, the sector is assumed to reduce by 2% per year. This is based on the Further Acceleration scenario from the hydrogen report published by HETI and Center for Houston's Future.

    b. All other sectors grow by 2% per year in all scenarios. This is aligned with the Texas Energy Policy Simulator NDC Pathway GDP growth for the state.

6. The following natural gas and electric device efficiencies for the directly electrified end uses are assumed.

TABLE E.
INDUSTRIAL END USE EFFICIENCIES

END USE AND DEVICE	NATURAL GAS EFFICIENCY	ELECTRIC EFFICIENCY	SOURCES
Heat pump	80%, based on steam generation from conventional boilers and CHP/ cogeneration	COP of 3	DOE 2018 MECS Footprint for Chemicals (NG) RTC Heat Pump Decision Support Tool (Elec) ACEEE Industrial Heat Report (Elec)
Thermal energy storage/electric boilers	80%, based on steam generation from conventional boilers and CHP/ cogeneration	95%	Note that electric boiler efficiency is higher (99% according to Schoeneberger et al.), though the value used is associated with thermal energy storage from correspondence with thermal energy storage startups (Elec)
Cracker	35%	55%	Shell presentation to Institute for Sustainable Process Technology, Slide 5 (NG and Elec)
Machine drive	35%	94%	DOE 2018 MECS Footprint for Chemicals (NG) Table 1, DOE Advanced Manufacturing Office (Elec)
Direct nonprocess use	33%	100%	Assumed

7. The following electricity intensities for each end use are assumed.

TABLE F.
ELECTRICITY INTENSITIES FOR SELECT INDUSTRY END USES

END USE AND DEVICE	ELECTRICITY INTENSITY	SOURCES
Green hydrogen	53 kWh/kg H2	
Blue hydrogen	2.5 kWh/kg H2	API, Hydrocarbon Processing, NREL, Oni et al, Progressive Energy, National Academies
Point-source CCS	0.1 MWh/tonne CO2 captured	Electricity demand varies widely depending on the CO2 source, CO2 capture method, and what is done with CO2 after capture (compression, transfer to storage, purification for utilization, etc.). This number is based on review of a variety of processes, sources, and CO2 resting place (JCCS report, RITE presentation (p33), Air Liquide catalog (p6), OSTI report, API)

Transport and buildings load impact methodology

Device stock data is combined with average hourly load profiles by device in the load impact calculation:

- Average hourly load profiles of building heating and cooling for both commercial and residential buildings across a year is derived using NREL's ComStock and ResStock Analysis Tools.
- Dynamic load data from Replica is used to get average charging patterns for low-, medium-, and heavy-duty vehicles (LDV/MDV/HDV) for specific years. The remaining data across all vehicle types is interpolated to get dynamic charging profiles from 2023 to 2050 by hour.
- Average hourly load profiles by device are combined with total device stock from the stock rollover analysis to calculate total hourly transport and building load.

Grid infrastructure impact methodology

Impact of Transportation and Building Load Growth on Distribution Infrastructure

- Given feeder demand data on today's CNP system, year-on-year forecasted demand on all distribution feeders is calculated.
- For every year, the forecasted increase in system demand (for transportation and building loads, excluding industrial load growth) is equally distributed to every feeder in the CNP system in that year, regardless of loading status in the previous time step. Thus, in year t, the demand of a feeder can be expressed as:

$$\text{Feeder Demand}_t = \text{Feeder Demand}_{t-1} + \frac{\text{demand forecast}_t - \text{demand forecast}_{t-1}}{\text{number of feeders in system}_t}$$

- To account for continued distribution system capacity expansion in the CNP service territory, the existing annual rate of feeder buildout (30 feeders per year) is assumed to continue for the study period until 2050. Thus, the value for 'number of feeders in system in year *t'* increases every iteration.
- This approach is conservative as it likely overestimates distribution system overload. Feeders are assumed to be added at a constant rate, and load from over-capacity feeders is not reallocated to new feeders. CenterPoint will add load to feeders based on demand in a given localized area. Once a feeder is loaded 70-80%, a new feeder will be constructed nearby.

Impact of Industrial Load Growth on Transmission Infrastructure

- The objective is to determine the number of transmission lines to be built by 2050, depending on various preset values of the maximum loading % on a single transmission line. A linear equation was set up to establish this relationship.
- If *Ptarget* is the targeted maximum loading limit of a transmission line in a future year (in MVA), and *Ptoday* is the average loading of a transmission line today (in MVA), then to calculate *x*, the number of transmission lines to be built to ensure transmission lines are not loaded beyond *Ptarget*, the equation below is used:

  $Ptarget*(x + 179)=(Ptoday * 179) + industrial\ load\ growth$

- With the limited available data, predicting the impact of other key factors influencing transmission lines, such as the location of transmission lines, location of loads, actual loading % of transmission lines, and which lines are key for system congestion is not possible.

Demand flexibility analysis methodology

TABLE G.
DEMAND FLEXIBILITY AND DISPATCHABILITY ASSUMPTIONS

SECTOR	TECHNOLOGY OR END USE	LOAD FLEXED (2030)	LOAD FLEXED (2050)	NOTES AND ASSUMPTIONS
Transportation	Light-duty vehicles (LDV)	35%	35%	Holy Cross Energy (HCE)
	Medium-duty vehicles (MDV), heavy-duty vehicles (HDV)	85%	85%	Nature, assumes constant, minimal power charging
Buildings	Space heating, water heating	10%	10%	Energy and Buildings, IEEE, Annex 67 (IEA), assume no thermal storage solutions (e.g., water tanks) or major upgrades, focusing primarily on the implementation of "smart" heating and cooling systems
Industry	Process heat, machine drive, other facility needs (e.g., office HVAC)	10-20%	10-20%	DOE, energies, assume batch loads that can adjust their process schedules to optimize energy use
	Electrolyzers	20%	80%	IEA, IRENA 1, IRENA 2
	Electrified high-temperature process heat	100%	100%	RTC

GHG analysis methodology

- Grid emissions intensity
  - Fuel-specific GHG intensity (lb/MWh) in ERCOT determined by average of fuel-specific carbon intensity reported on eGrid from 2018-2021. Data Explorer | US EPA
    - GHGs = CO2, SO2, NOx, CH4

TABLE H.
GRID EMISSIONS INTENSITY BY GENERATION SOURCE

GHG	INTENSITY FROM COAL (LB/MWH)	INTENSITY FROM NATURAL GAS (LB/MWH)
CO2	2252	870
SO2	3.19	0.007
NOx	1.195	0.542
CH4	0.256	0.016

Fossil fuels: coal, natural gas.

- 4 versions of the ERCOT generation mix were considered:

Three scenarios for year 2037:

1. Current trends (2022 LTSA): trajectory based on historic precedence
2. Expanded system outlook (2022 LTSA): includes more solar and battery storage compared to current trends, but also recognizes siting and interconnection issues
3. Demand side evolution (2022 LTSA): higher demand than current trends, but with large flexible loads, managed EV charging, and greater EV adoption

One scenario for year 2035:

1. Renewables mandate (2020 LTSA): Significant solar and wind adoption as well as a carbon tax at $40/ton

Sample calculation:

$$\text{Annual } CO_2 \text{ from coal generation (lb)} = 3.97\% * 601975\ GWh * \frac{1000\ MWh}{GWh} * \frac{2252\ lb}{MWh} = 5.38 * 10^{10}\ lb$$

$$\text{Annual } CO_2 \text{ from natural gas generation (lb)} = 38.03\% * 601975\ GWh * \frac{1000\ MWh}{GWh} * \frac{870\ lb}{MWh} = 1.99 * 10^{11}\ lbs$$

$$\text{Annual } CO_2 \text{ emitted by grid (lb)} = 1.99 * 10^{11} + 5.38 * 10^{10} = 2.53 * 10^{11}\ lbs$$

$$\text{Average } CO_2 \text{ intensity of grid } \left(\frac{lb}{MWh}\right) = \frac{\text{annual } CO_2 \text{ emitted by grid (lb)}}{\text{annual demand (GWh)}} * \frac{1000\ MWh}{MWh} = 420.2654 \left(\frac{lb}{MWh}\right)$$

TABLE I.
GRID EMISSIONS INTENSITY BASED ON ERCOT LONG-TERM ASSESSMENT

	ANNUAL DEMAND (GWH)	COAL %	NATURAL GAS %	CO2 INTENSITY (LB/MWH)
Current trends	601975	3.97	38.03	420.2654
Expanded system outlook	601975	4.25	41.66	458.152
Demand side evolution	772811	3.7	54.69	559.127
Renewables mandate	629391	0.2	33.96	299.956

- Assume blue hydrogen lifecycle emissions of 3.4 kg CO2e/kg H2 from the Greenhouse Gases, Regulated Emissions, and Energy Use in Technologies (GREET) model
- Assume CCS capture rate of 90%, which is typical for analyses like ours

Hydrogen sensitivity analysis methodology

- Electricity needed:
  - Electricity req for blue H2 = 2.5 kWh/kg (Electricity for CCS in kWh per kg H2_blue H2.docx)
  - Electricity req for green H2 = 54 kWh/kg (CAI info?)
- RMI internal tracking of H2 projects announced in TX and LA suggests 35% green, 65% blue today, hence 35:65 for 2030 estimates
- HETI members interviewed do not indicate preference for green vs blue, hence 50:50 in 2050.

- Exports: internal RMI analysis suggests that landed LCOH in EU from could be as low as 2.5-3.5 €/kg H2 including PTC. This is significantly lower than LCOH from any other country exporting.
    - 2030 US estimates: 3-5 tons
    - 2050 estimate: 15-20 tons

Population and GDP growth

- Growth of 0.7%/year is applied to consumer-facing sectors (LDVs, residential buildings)
    - This is based on projected population growth in the counties covered by the CenterPoint service territory from the 0.5 Migration Scenario of the Texas Demographic Center.
- Growth of 2%/year is applied to all commercial sectors (MDVs, HDVs, commercial buildings, industry)
    - This is aligned with the Texas Energy Policy Simulator NDC Pathway GDP growth for the state.

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